The Dissertation Committee for Yael Rebecca Glazer
certifies that this is the approved version of the following dissertation:

A Techno-Economic Framework for Mitigating Environmental Liabilities from Unconventional Oil and Gas Operations in the United States

Committee:

Michael E. Webber, Supervisor

Desmond F. Lawler

Charles J. Werth

Paola Passalacqua

Charles Kreitler

A Techno-Economic Framework for Mitigating Environmental Liabilities from Unconventional Oil and Gas Operations in the United States

by

Yael Rebecca Glazer

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To my sons, Adam and Abe. Without whom I probably would've finished this much sooner. Can't think of a better reason to have taken so long. To my husband, Ben. He proofread this dissertation. If that's not love, I don't know what is.

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A Techno-Economic Framework for Mitigating Environmental Liabilities from Unconventional Oil and Gas Operations in the United States

Yael Rebecca Glazer, Ph.D.
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Supervisor: Michael E. Webber

Unconventional oil and gas (O&G) activity is associated with many environmental liabilities including 1) high water use, 2) substantial volumes of generated wastewater, and 3) flaring of co-produced natural gas. The work in this dissertation aims to holistically examine and find strategies to mitigate these environmental challenges through three studies:

1. Designing a method to select the most appropriate wastewater treatment technology or product based on numerous metrics and across many potential options.

2. Conducting an inventory and engineering assessment of the flared gas and wastewater.

3. Building a decision tree model to investigate and compare the economic feasibility of several potential traditional and nontraditional produced water management pathways, including treatment, disposal, discharge, and crop production.

Based on the results of these analyses, the following general conclusions are drawn:

The first study shows, through the tremendous number of technologies and products that claim to handle wastewater associated with O&G activities, mechanical vapor recompression, and to a lesser extent, reverse osmosis are the top contenders when treating to freshwater standards is desired. In the process, a down-selection tool that can be tailored to an operator's specific requirements and a database containing many of the available technologies and products were created.

The second study shows that from the seven prominent shale regions included in this analysis, Marcellus/Utica (in the Northeast), Bakken (North Dakota), and Niobrara (Rocky Mountains) flared between 2 and 48 times the amount of natural gas needed to provide energy for treatment of their wastewater volumes. The Permian Basin, Eagle Ford, and Haynesville did not have sufficient flared gas to treat wastewater produced in each respective region. As such, these regions would require additional energy sources for wastewater treatment.

The third study shows that several nontraditional produced water management pathways might be economically feasible depending on the realized 1) price for the commodities produced and 2) cost associated with implementing the strategy. In this case, the traditional pathway to minimally treat and discharge to a nearby stream had the highest expected value by a slim margin over growing switchgrass onsite. This result suggests that further investigation should be considered to determine, with greater certainty, the attainable price for switchgrass.

These general conclusions, along with further details, provide insight into the challenges and mitigation strategies with some of the environmental liabilities associated with unconventional O&G activity. As onsite resources (e.g., available water) become more constrained and regulations become more stringent (e.g., curtailment of flaring), implementing these or similar approaches to the industry's waste streams will become increasingly imperative.

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Chapter 1

Introduction

1.1 Motivation

The United States has experienced a dramatic resurgence in domestic oil and natural gas production over the last decade. Much of the increase is due to the rapid expansion in the use of horizontal drilling and hydraulic fracturing (HF), unconventional well drilling, and completion techniques to extract abundant hydrocarbon resources from various shale plays across the country. Domestic energy production is often viewed positively from both political and economic standpoints, since it reduces dependence on foreign energy sources and creates jobs. However, unconventional oil and gas (O&G) activity often has environmental liabilities including 1) significant freshwater requirements, 2) large volume of wastewater (WW) that must be managed and properly disposed, and 3) natural gas flaring (i.e., burning), among others.

While unconventional O&G practices vary by shale region and sometimes even from one well to the next, operators typically source water used for HF from nearby surface water or groundwater, inject the generated WW via a salt water disposal (SWD) well, and flare associated natural gas that cannot be brought to market. The impact and severity of these environmental challenges vary on a regional level depending on a variety of factors, including the geology of the shale formations, prevailing climate conditions, access to water resources, access to nearby wastewater disposal sites, existing infrastructure, and state and local regulations.

The real and perceived environmental liabilities associated with unconventional O&G operations have received widespread attention from the media and public. Additionally, many O&G companies, non-profit organizations, foundations, and government agencies study these challenges in search of technically- and economically-feasible solutions. Given the fast-paced and volatile nature of the industry, unconventional O&G activity has progressed at a remarkable rate, while research, solutions, and policies to address the environmental issues typically lag behind.

The growth in unconventional O&G operations and its associated environmental liabilities come at a time when the world is grappling with water scarcity issues, food shortages, and increasing awareness for and concern with the implications of climate change. Flaring is a real challenge yet sufficient pipeline infrastructure is not being built to bring that gas to market. Furthermore, regions of the US that were previously never known to be earthquake-prone are now experiencing induced seismicity resulting from wastewater injection underground. All of these issues can be associated with unconventional O&G activity, making tackling and mitigating the environmental challenges evermore critical. As such, seeking to build a holistic framework that combines technical, economic, and policy considerations associated with mitigating environmental liabilities from unconventional O&G operations is timely and relevant.

The framework includes both traditional and nontraditional ideas and methodologies presented in the form of three research objectives:

1. Develop a methodology for selecting viable and appropriate wastewater treatment technologies for O&G wastewater based on a variety of metrics including wastewater quality, wastewater quantity, and desired use of the treated water.

2. Determine the potential for using the energy from flared natural gas to power wastewater treatment in the major shale plays across the US. To conduct this

assessment, data on the volumes of wastewater and flared gas associated with unconventional O&G activity by shale region will first be compiled and curated.

3. Compare possible traditional and nontraditional wastewater management strategies using a decision analysis model.

1.2 Paper Organization

The background, research, and analysis for the objectives of this dissertation are presented and discussed in the following chapters.

Chapter 2 presents background and context on unconventional O&G activity in the US and its various environmental challenges. A literature review and additional details on the research objectives are also provided in this chapter. **Chapter 3** describes the methodology employed to develop a wastewater treatment down-selection tool. Application of the tool using wastewater characteristics from several regions is also performed. **Chapter 4** provides an inventory of the flared natural gas and wastewater volumes in the major shale regions in the US. It also includes an engineering assessment to determine in which regions there is sufficient energy from flared natural gas to power water treatment. **Chapter 5** details a decision tree model and analysis to choose between several traditional and nontraditional produced water management strategies, given a specific O&G site's attributes. **Chapter 6** offers a high-level summary of the results and conclusions of this dissertation plus potential future work.

In addition to the information presented in the chapters above, the Appendices contain additional work and information that helped inform the various parts of this research.

Chapter 2

Background and Literature Review

The recent growth in domestic energy production has been largely attributed to the extraction of hydrocarbons from shale formations across the United States. Figure 2.1 shows a map of current and prospective shale plays in the contiguous US. Between 2008 and 2015, domestic crude oil production nearly doubled with 2016 production rates at approximately 9 million barrels per day (shown in Figure 2.2), making the US the top producer of petroleum hydrocarbons in the world [4, 9].[1] Figure 2.3 shows natural gas production grew about 50% between 2005 and 2015 after decades of little or no growth with approximately 28.5×10^{12} cubic feet produced in 2016 [10]. Since 2009, the US has been the top producer of natural gas in the world [9]. Furthermore, as Figure 2.4 shows, future US domestic dry natural gas production is projected to continue increasing and, by 2035, be dominated by extraction from shale deposits [11].

Aside from creating jobs in the US and curtailing our reliance on foreign energy, the *Shale Revolution* (as it is often termed) is credited with lowering gasoline and natural gas prices while simultaneously reducing the carbon intensity of the electric grid by facilitating natural gas over coal for power generation. The move to more natural gas-fueled electricity means cleaner power generation, since natural gas is less carbon-intensive than coal on a per-unit-of-energy-generated (e.g., MMBTU) basis. In fact, US energy-related carbon emissions fell 12% between 2005 and 2015 due

[1] The US has been the top petroleum hydrocarbons producing nation since 2013 [9].

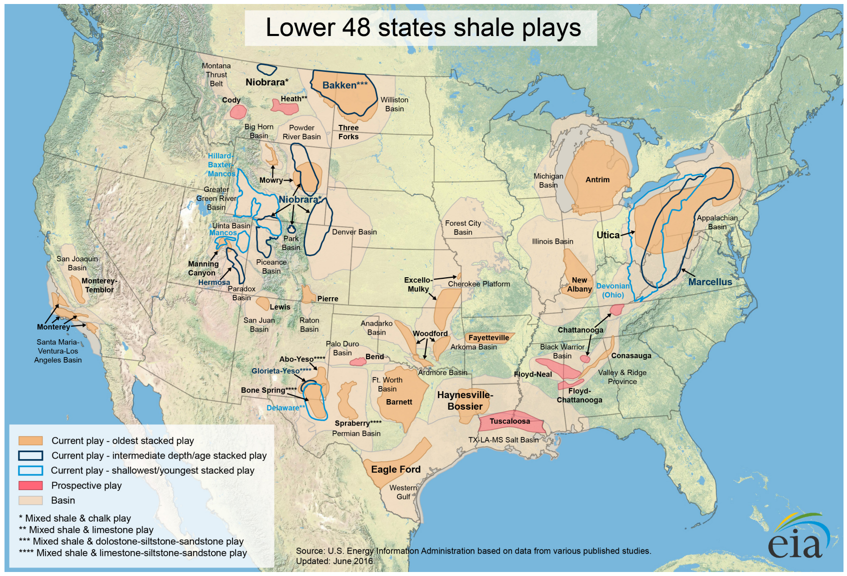

Figure 2.1: The shale regions in the contiguous US and their status as of June 2016 (i.e. active vs. prospective plays) [3].

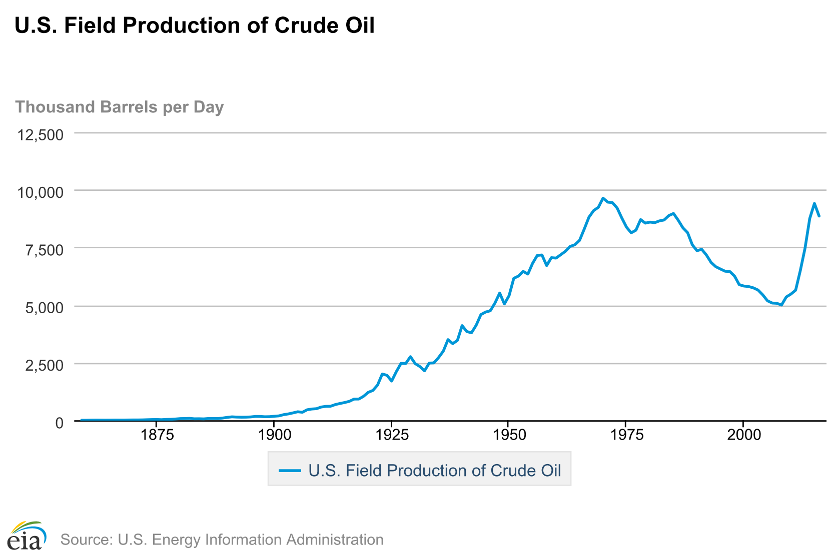

Figure 2.2: US crude oil production from 1850 to 2016. The spike in production starting around 2010 is primarily due to the rapid growth in activity in shale regions [4].

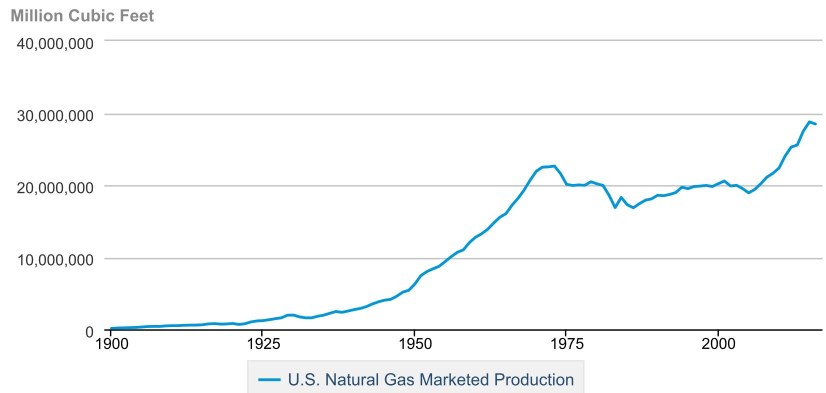

Figure 2.3: Natural gas marketed production in the US from 1900 to 2016. The steep increase in production starting in the mid-2000 is primarily due to rapid growth in activity in shale regions [10].

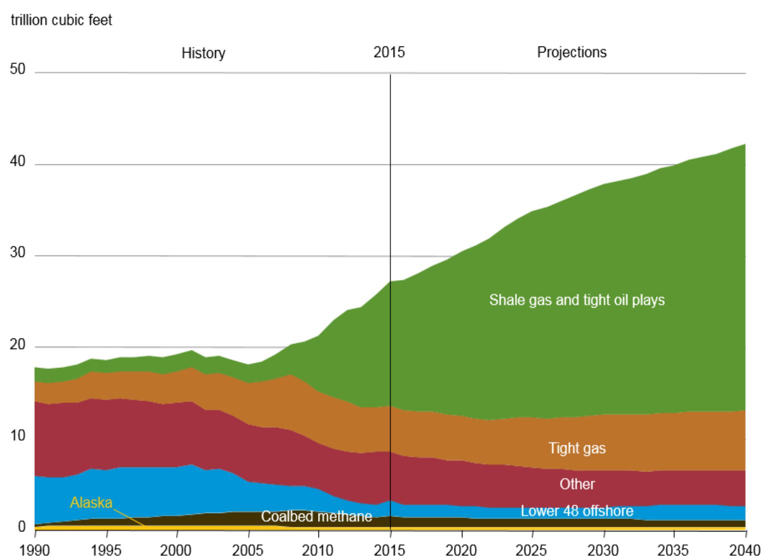

Figure 2.4: Historical and projected US natural gas production by type. Natural gas from shale and tight oil plays has become a significant portion of the overall production and is expected to become the dominant contributor to overall US natural gas production by 2040 [11].

mostly to changes in the electric power sector (i.e., increase in electricity generated using natural gas compared to coal) [12].

2.1 Unconventional Oil and Gas Practices in the United States

This section describes at a high level unconventional O&G practices in the US. It also identifies the various environmental concerns and waste streams focused on in this dissertation.

2.1.1 Drilling the Well

A wellbore is drilled from the surface to the depth of the formation. Water based fluids are used during drilling to cool and lubricate the drillbit and stabilize the wall of the wellbore [13]. The vertical portion of the wellbore is often thousands of feet deep, extending far below the water table as shown in Figure 2.5. Once the shale formation is reached, the drillbit is often turned so that drilling can continue laterally (i.e., horizontal drilling) for thousands of feet, thereby increasing the well's contact with the formation. Multiple lateral stretches can be drilled from the same drilling pad thus potentially minimizing the impact to the surface [13].

2.1.2 Well Completion

There are many techniques to complete a well including hydraulic fracturing.[2] Typically when HF is intended, surface casing (often made of steel) is installed in the well and cemented in place. The casing serves as an impermeable barrier preventing interactions between the fluid inside the well and groundwater. When properly installed, the casing prevents groundwater contamination due to O&G operations and

[2] Other well completion techniques include open hole, slotted liner, and gravel pack, among others.

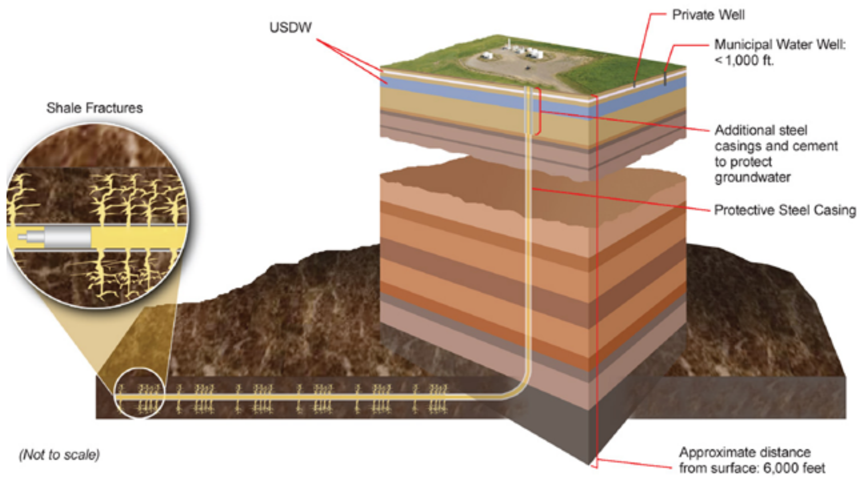

Figure 2.5: High-level illustration depicts a horizontal well in a shale formation [5].

helps maintain the integrity of the well.

Next a perforating gun is sent downhole to make holes in the surface casing and cement and cracks or fissures in the shale [13]. During HF, cracks are extended in the shale formation and maintained by injecting anywhere from 8-50 thousand m^3 (2-13 million gallons) of hydraulic fracturing fluid (or "frac fluid")–composed of water, proppant (often sand), and chemicals–at high pressures [14].[3] The proppant in the fracturing fluid helps keep the cracks open to allow fluid to flow from the formation into the well. Figure 2.5 illustrates a well horizontally drilled in the shale formation after its been fractured with a perforating gun. The horizontal portion of the well is often hydraulically fractured in stages. That is, a single well may undergo many rounds of HF each requiring large volumes of frac fluid.

According to Kondash and Vengosh, between 2005 and 2014, drilling and completion of unconventional oil and gas wells used approximately 940 million m^3

[3]The vast majority of frac fluid is made up of water followed by proppant and chemicals. The exact concentrations of the constituents in frac fluid vary depending on several factors; however, water and sand generally make up 99% of frac fluid by volume [13, 15].

(248 billion gallons) of water in the ten regions they investigated [16].[4] To put this volume of water into context, it is approximately the amount required to provide each person in the US 100 gallons per day for 7.7 years.[5]

It should be noted that while water use for drilling and completion of unconventional wells is significant, it remains less than 1% of overall water withdrawals in the US [17]. By comparison, in Texas, irrigation followed by municipalities are the largest water users at 50% and 34%, respectively [18]. Still, the industry's water use can be much higher on a local level. For example, in Johnson County, Texas, water use for HF represented 29% of total county water usage in 2008 [19].

2.1.3 Generated Wastewater

Wastewater from unconventional O&G activity is comprised of flowback, produced water, and drilling muds and is considered a significant challenge as it can be hazardous to human health and the environment if improperly managed. Kondash and Vengosh estimated that between the early 2000s and 2015, 803 million m^3 (212 billion gallons) of WW was generated from the ten shale regions investigated in their study [16].

Frac fluid that returns to the surface over the initial period after well completion is termed flowback (FB). The composition and constituents of FB are often similar to the frac fluid. After the initial period of production, water naturally occurring in the formation, termed produced water (PW), will also rise to the surface alongside the oil and gas over the lifetime of the well. The amount of FB and PW that comes back varies by region and depends significantly on the geology of the for-

[4]The ten shale regions investigated in Kondash and Vengosh's study include the Barnett, Eagle Ford, Fayetteville, Haynesville, Marcellus, Niobrara, Woodford, Bakken, Permian, Monterey-Tremblor.

[5]Based on a population of 323 million.

mation. For example, the amount of FB and PW that returns to the surface over the lifetime of the well as a percentage of the initially injected fracturing fluid is 20% in the Eagle Ford and can be over 200% in the Permian Basin [20]. The WW quality also varies significantly by shale region. Unique attributes of shale WW are discussed in further detail in Section 2.3 and Appendix D. Details on common WW constituents are listed in Table 3.2.

2.1.4 Natural Gas Flaring

Flaring is another significant environmental liability associated with unconventional O&G operations. In wells where both oil and gas are produced, and where there is insufficient natural gas gathering infrastructure, operators will flare some portion of the associated natural gas onsite rather than deliver it to market. Natural gas is also flared for safety reasons since it is less dangerous to flare the natural gas than to have combustible gases in the ambient environment. The combustion of natural gas in flares yields no productive work while continuing to produce emissions.

In addition to safety reasons, natural gas is flared instead of vented into the atmosphere because methane, the predominant constituent of natural gas, is 25 times more potent a greenhouse gas than the carbon dioxide emitted as a byproduct of methane's combustion [21].[6] The amount of flaring occurring at a wellhead varies by shale region and even from well to well within a region. Many organizations and governments would like to see a significant curtailment in flaring. For example, in 2015 the World Bank announced an initiative to end routine, non-safety-related flaring around the world by 2030 [22].

Flaring volumes and rates vary by region. Approximately 0.9% of natural gas

[6] Based on a 100-year time horizon, methane has a Global Warming Potential of 25 [21].

produced in Texas was flared in 2014 corresponding to about 65 billion cubic feet [23]. By contrast, rates of flaring reached over 35% of natural gas produced in the Bakken in recent years, where approximately 120 billion cubic feet were flared in 2014 [24]. It should be noted that the steep drop in oil prices in 2015, which caused a curtailment in oil production in the Bakken, coupled with flaring reduction targets set by the North Dakota Industrial Commission (NDIC), resulted in a substantial reduction in natural gas flaring in teh Bakken region.

2.2 Current Practices Across US Shale Plays and Common Environmental Liabilities

The shale regions across the US cover a variety of terrains and climates. Many shale plays traverse several states, such as the Bakken in North Dakota and Montana and Haynesville in Texas and Louisiana, as shown in Figure 4.1. While well completion techniques, water acquisition, and waste stream management practices vary by region, many aspects remain relatively consistent across the country, including: the majority of water necessary for well completions is sourced from nearby surface water or groundwater, the bulk of WW is injected deep underground (presumably never to be seen again) via SWD wells, and associated natural gas is flared for safety reasons or when the infrastructure cannot support bringing it to market. Notable exceptions to these commonalities exist, such as the relative infrequency of WW disposal via SWD wells in Pennsylvania [25]. In some regions, the WW is relatively clean and can be discharged to a nearby body of water with minimal treatment. While the details of how each of these commonalities is handled is often region-specific, similar challenges exist across the country's shale plays.

In recent years, a growing percentage of the WW in many shale regions is treated and reused mainly for the purpose of completing subsequent wells [26]. In some areas, such as the Marcellus shale, this trend is to avoid underground injection due to a limited number of SWD wells, while in other regions like the Permian Basin, it is due to water scarcity issues. In addition, there is growing concern that underground injection is causing seismic activity in areas not historically known to have earthquakes, such as Oklahoma and Ohio [27, 28].

2.3 Unique Attributes of Shale Regions

While similar environmental challenges are present in most shale areas, their impact and severity on a regional level depends on a variety of factors, including the geology of the shale formations, prevailing climate conditions, access to water resources, access to nearby wastewater disposal sites, existing infrastructure, and state and local regulations. Variations in geology from one region to the next can affect water and chemical requirements for well completion and quantities and qualities of the WW generated. For example, wells hydraulically fractured in the Niobrara require an average of 12,500 m^3 (3.3 million gallons) per well while those in the Marcellus require approximately 21,000 m^3 (5.6 million gallons) per well [29]. Wells in the Permian Basin in west Texas generate significant volumes of WW while the volumes generated from wells in the Marcellus/Utica region are much lower. In addition, WW in the Bakken shale in North Dakota has upwards of 200,000 mg/ℓ of total dissolved solid (TDS) concentration while the wells in the Eagle Ford shale in southern Texas generate cleaner WW with approximately 40,000 mg/ℓ TDS concentration [30, 31]. The Permian Basin region is known to be highly arid with water scarcity issues while the Marcellus region generally has sufficient water availability. Table 2.1 summarizes many of these characteristics for seven shale plays in the US.

Differences in water availability and use, WW quantity, WW quality, and

Table 2.1: Summary of key characteristics for seven shale regions. The Palmer Drought Severity Index (PDSI) was used to describe the general water availability in a region and takes into consideration precipitation and temperature, among other factors. Descriptions of volumes of wastewater and flared gas are on a cumulative basis for their respective regions [30–33].

Shale Region	Predominantly Oil or Gas Play	PDSI Index Classification	Wastewater Volume	Wastewater Quality	Average TDS Concentration (mg/ℓ)	Flared Gas Volume	Sufficient Nearby Disposal
Bakken	Oil	Slightly Wet	Low	Poor	250,000	Very High	Yes
Marcellus/Utica	Gas	Near Normal-Slightly Wet	Very Low	Moderate	130,000	Medium	No
Eagle Ford	Oil & Gas	Insipient Dry Spell	Medium	Good	40,000	High	Yes
Niobrara	Oil & Gas	Mild to Moderate Drought	Very Low	Good	25,000	Low	Yes
Haynesville	Gas	Near Normal	Low	Poor	120,000	Low	Yes
Permian Basin	Oil & Gas	Insipient Dry Spell	Very High	Moderate	140,000	Medium	Yes

associated natural gas volumes play a central role in helping operators determine how to handle their various waste streams. In addition, these regional differences make it difficult to apply one approach to mitigating environmental liabilities across all areas. That is, there is no "one size fits all" solution to mitigating waste streams associated with unconventional O&G activity.

2.4 Research Objectives

Since the most recent boom began in the mid-2000s, the environmental risks and trade-offs associated with unconventional O&G activity has piqued the interest of industry, the academic community, regulatory agencies, and the general public. As a result, numerous book chapters, academic journal papers, newspaper articles, and blog posts have been written about the various environmental challenges associated with HF. In addition, the environmental, economic, and social impacts of unconventional O&G activity are widely studied in many universities and research organizations around the world.

Unconventional O&G waste streams are often handled on an individual basis. For example, as shown in Figure 2.6, WW and associated natural gas are handled independent of one another via underground disposal and flaring, respectively. By comparison, this work takes a holistic approach to contemplating unconventional O&G waste stream management by building a framework that considers a range of tools and strategies for reducing the environmental impacts of HF. This framework is more similar to the scenario depicted in Figure 2.7, wherein waste streams are repurposed for beneficial use. For example, WW can be treated and reused and natural gas that would otherwise be flared can be used to power water treatment, among many other possibilities for beneficial reuse.

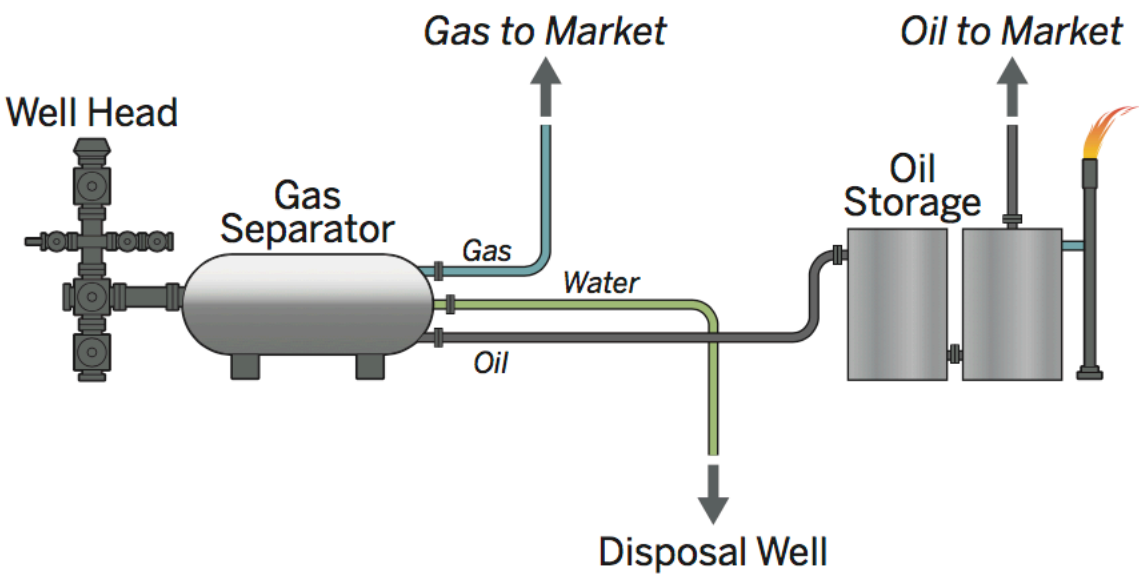

Figure 2.6: Status quo of waste streams associated with unconventional O&G activity is that WW is generally disposed of via SWD wells and natural gas that cannot be sold is flared.

Each research objective in this dissertation aims to contribute to the overall concept of a holistic approach to mitigating HF waste streams. The following sections describe how the research objectives build upon or compare to what is already known in the literature or industry.

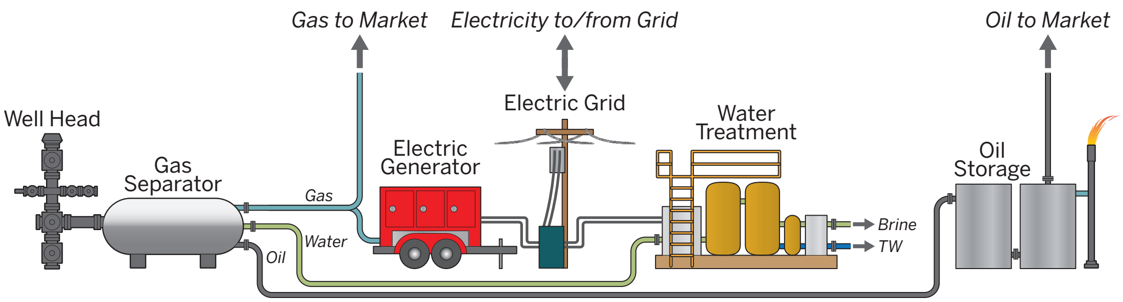

Figure 2.7: A holistic look at managing waste streams from unconventional O&G activity often includes treating WW for potential beneficial use. In addition, natural gas that cannot be sent to market could be converted to electricity via an onsite generator and used either onsite or sent to the electric grid. TW stands for 'treated water'.

2.4.1 Objective 1—Build a Wastewater Treatment Technology Down-selection Tool

Objective 1 comprises a methodology for selecting the appropriate water treatment technology depending on a variety of considerations including the wastewater quantity and quality and desired beneficial use of the treated effluent. The O&G industry's interest in reuse and recycling of generated WW has grown especially rapidly in areas with 1) water scarcity, 2) inadequate wastewater disposal options, or 3) increasing induced seismic activity. As the industry's interest has grown, so has the number of journal articles describing the merits of various wastewater treatment technologies and products [34–36]. Many journal articles and reports review the range of water treatment technologies available and include the advantages and limitations to each of them [37–40].

Both the Colorado School of Mines (CSM) and the National Energy Technology Laboratory (NETL) claim to provide online tools that are meant to aid users in selecting an appropriate water treatment technology based on a variety of inputs.

The details of the CSM tool entitled, “The coal bed methane (CBM) produced water treatment and beneficial use screening tool,” were published online in 2010 and in the literature in December 2013 [41, 42]. The tool includes four modules: 1) Water Quality, 2) Treatment Selection Module, 3) Beneficial Use Screening, and 4) Beneficial Use Economic Model. While this tool provides a comprehensive framework for choosing an optimal water treatment technology, given wastewater quality and desired use for the treated water, it suffers three drawbacks including 1) it is designed to address wastewater associated with CBM production (but not shale production), 2) the scope of the tool encompasses five CBM basins in the Rocky Mountain region, and 3) while plenty of documentation around the tool is available online, the tool itself is not. Several attempts to obtain the tool by emailing the author, as the online instructions indicate, went unanswered.

NETL offers the Produced Water Management Technology Identification Module [43]. This interactive tool is designed to facilitate “identifying appropriate PW management strategies for a given well location and circumstances” by guiding the user through a series of questions to scope the problem [43]. Several attempts were made to access this tool online, but the web page repeatedly timed out and failed to load.

By publishing a tool focused on shale production and making it publicly available, this work contributes to the field. Through numerous conversations with employees at prominent O&G companies, it is clear that many organizations were grappling with the following question: If we decide to treat the wastewater associated with unconventional O&G activity, which technology (or set of technologies) will best suit our needs from the numerous available? Evaluating all commercially available and emerging technologies and products requires considerable time and effort. As such, this objective aims to aid operators in down-selecting water treatment technologies from the multitude of options available to them.

2.4.2 Objective 2—Calculate the Technical Potential to Use Energy from Flared Natural Gas to Power Wastewater Treatment in Major Shale Regions in the US

One way to mitigate both onsite flaring and wastewater disposal is to repurpose the natural gas that would otherwise be flared to power onsite water treatment. Coupling these two waste streams creates a valuable commodity of treated water which could subsequently be used for beneficial purposes. The idea of coupling flared gas (FG) energy with WW treatment is not investigated in the literature except in the work found in this dissertation and the author's previous publications focused on unconventional O&G activity in Texas [44, 45]. As such, Chapter 4 seeks to fill that knowledge gap by determining which of the major US shale regions have sufficient energy from flared gas to meet the energy requirements for HF wastewater treatment.

Determining the technical feasibility of this concept requires temporally and spatially resolved data on the volumes of WW and FG for the shale regions of interest. Several studies have reviewed the volumes of WW associated with O&G operations, including Veil's "US Produced Water Volumes and Management Practices in 2012" report and Kondash and Vengosh's journal article "Water Footprint of Hydraulic Fracturing" [16, 46]. Veil compiles produced water volumes for 2012 by state and, where possible, distinguishes between conventional and unconventional sources. While the report contains a significant amount of information and reveals the large PW volumes in the US, most of the data are reported for the state as a whole and not broken down by well or shale region. In addition, data are only available for one year. On the other hand, Kondash and Vengosh reported cumulative WW volumes by region over 6-10 years of operation. While the report is useful in understanding overall WW generation for unconventional O&G, it lacks temporal resolution.

Greenhouse gas (GHG) emissions from unconventional O&G operations have also been investigated within the academic community. Allen et al. took direct measurements of methane emissions at 190 onshore natural gas sites in the US to estimate total annual emissions on a national scale [47]. Clark et al. performed a Life Cycle Analysis to compare the GHG emissions for natural gas recovered from unconventional and conventional wells at each stage, including well drilling, production, processing, transmission and distribution, and end use [48]. O'Sullivan and Paltsev estimate the potential fugitive emissions during hydraulic fracturing in five shale gas regions in 2010 [49]. Even the EPA releases an annual report that tracks US GHG emissions by source that includes high level information regarding O&G operations [50]. Despite these various studies, data on volumes of natural gas flared remain incomplete with minimal data spatially and temporally resolved.

2.4.3 Objective 3—Build a Decision Tree Model for Evaluating Traditional and Nontraditional Pathways for Managing Produced Water from Oil and Gas Activity

Despite the significant attention to the challenges posed by WW, the published literature to date contains little discussion about methodologies or analytical frameworks that can be used for determining the best water management pathway for a particular O&G site given its unique characteristics, local market conditions, and prevailing regulatory context. As such, the goal of this objective is to develop a framework to assess technically and economically feasible management pathways for treated WW including novel or nontraditional approaches.

While some literature discusses potential treated WW beneficial reuse applications, most assume subsequent well completions as the main option. The few that suggest other alternatives do not perform an economic analysis of the suggested applications. One exception is the "coalbed methane produced water screening tool" developed by CSM in collaboration with Kennedy/Jenks Consultants and Argonne National Laboratory discussed in Section 2.4.1 [41]. The journal article describes that the tool allows the user to input information on a variety of metrics and then reveals which beneficial use strategies are most cost-effective. However, no details of the formulas and algorithms applied were found. Other than this tool, no other academic literature on water management decision making was found. This lack of literature is likely due to the fact that most financial modeling on waste stream management is done within O&G companies who rarely share the results externally. Despite the absence of publicly available information, or perhaps as a result, many companies are interested in finding economical and sometimes nontraditional ways to extract value from waste streams.

For this objective, decision analysis tools and financial models are used to determine the optimal beneficial use strategy for PW. The tool is flexible in that the user can update information as it becomes available to fine-tune the decision.

2.4.4 Shale Regions Explored in this Work

Extensive consideration was given to which US shale regions to focus on when defining the scope of this work. The criteria that were considered included data availability, production volumes, water scarcity concerns, disposal concerns, regions receiving significant media/academic attention, and collaboration opportunities with industry partners, among others. A different subset of the US shale regions is investigated in each research objective.

In Research Objective 1, knowledge on the Niobrara and WW quality data provided by an industry partner for the the Eagle Ford, Marcellus, and Bakken shale regions were used to test, validate, and demonstrate the down-selection tool's capabilities. Research Objective 2 focuses on the seven shale regions representing the vast majority of growth in O&G operations in the US during the time of the analysis: Permian Basin, Eagle Ford, Haynesville, Marcellus, Utica, Niobrara, and Bakken. Finally, thanks to availability of extensive information and data, the analysis in Research Objective 3 centers around a specific O&G site in a smaller play located in central Wyoming.

Additional information beyond what is discussed in the main body of this work can be found in Appendix D and focuses on water management and flaring practices in several of these shale regions.

2.5 Additional Environmental and Social Concerns Associated with Unconventional O&G Activity

While the overall aim of this work is to take a holistic approach to tackling water use, generated WW, and flared natural gas, these are not the only associated environmental concerns. Additional issues include but are not limited to:

- Soil and surface water contamination due to surface wastewater spills,
- Groundwater contamination due to improper well completion,
- Noise and light pollution due to O&G activity,
- Induced seismicity due to underground injection of WW,
- Methane leakage from O&G equipment,

- Increased dust, truck traffic, and road accidents in towns or areas with heavy O&G activity, and

- Rising rents and general strain on local infrastructure such as hospitals, schools, and law enforcement due to sharp influx of workers and their families in regions with high O&G activity.

While this work does not directly address the issues listed above, some of them will be mitigated by tackling water management and flared gas issues. For example, if the volume of wastewater requiring disposal is reduced through water treatment and beneficial reuse, less wastewater will need to be trucked and disposed via SWD wells. Reducing wastewater requiring disposal could lower the impacts associated with truck traffic and the risk of induced seismicity in certain areas. Similarly, light pollution will be curtailed if the natural gas that would have otherwise been flared is captured or repurposed. Therefore, focusing on ways to minimize the wastewater and flared gas waste streams will directly and indirectly address many of the environmental liabilities associated with unconventional O&G activity.

2.6 Industry Volatility

Oil prices fluctuate due to a variety of influences. Between April 2012 and December 2017, oil prices peaked at over $110 per barrel and fell to a low of $26 per barrel as shown in Figure 2.8. The inconsistent revenue stream due to the volatility in oil prices can make it challenging for O&G companies to tackle environmental concerns beyond regulatory requirements. Some regions are more sensitive to fluctuations in oil prices than others. For example, the dramatic drop in oil prices in 2014 resulted in varying levels of production declines in several oil-dominant shale regions, as shown in Figure 2.9.

Figure 2.8: West Texas Intermediate (WTI) crude oil spot prices between April 2012 and February 2018 [6].

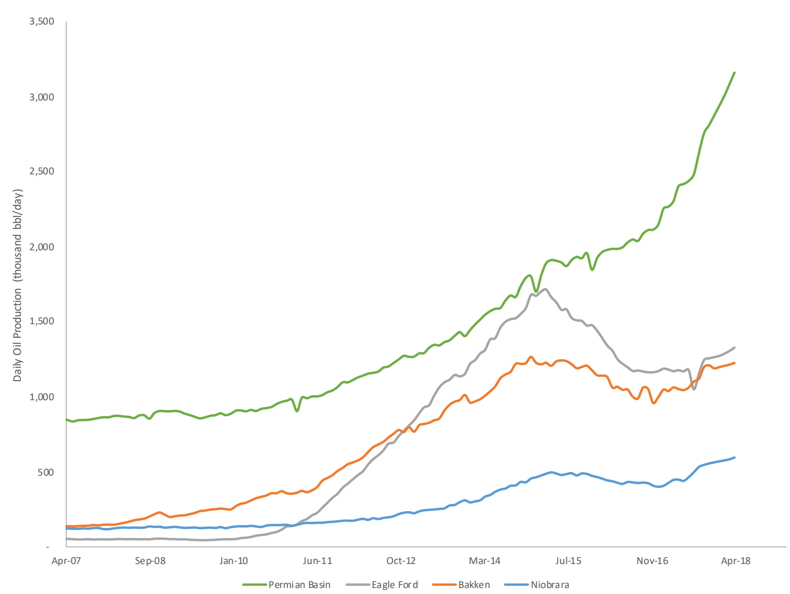

Figure 2.9: Daily oil production in the Bakken, Eagle Ford, Niobrara, and Permian Basin shale regions has increased since 2007 despite a significant drop in several areas after oil prices plummeted in 2014. Note that the drop in production varies by region with the Permian Basin impacted the least during that time, in fact, the Permian Basin has seen a significant increase in production since 2016 [51].

Chapter 3

Technologies for Treating Wastewater from Unconventional Oil and Gas Operations: A Review and Method for Selection

3.1 Introduction

Managing O&G WW is often a significant concern for operators. In many of the shale plays, the main method of WW management is injection underground in SWD wells. Injection is an effective WW management method especially in regions with sufficient number of SWD wells, where water resources are abundant, and induced seismicity is not a concern. However, in areas where the geology is not conducive to underground injection (e.g., Marcellus Shale), or in areas with growing water scarcity issues (especially coupled with growing HF water demands, such as the Permian Basin), WW treatment and reuse is growing in desirability to minimize both the WW volume requiring disposal and the cost of acquiring new water for subsequent well completions. As a result of these pressures, WW treatment and reuse has become more commonplace in many regions. Due to this growing trend the US O&G wastewater treatment market is estimated to reach $3.8 billion by 2025 [52].

WW quality and quantity varies depending on the region, the geology of the formation, and the constituents in the frac fluid. Furthermore, operators might have different intended uses for the treated water. As such, based on currently available technologies, there is no single treatment system that is ideal for all wastewaters. Instead, each operator must determine the optimal treatment scheme for their operations and desired use for the treated water from the many available or emerging technologies and products developed to treat O&G WW.

Through conversations with several O&G operators and environmental groups, it became apparent that many companies with the manpower and funds to do so were attempting to each conduct their own internal technology vetting and assessments. In general, information gathered in this process is kept confidential presumably to maintain a competitive advantage. Thus, this work seeks to add value by creating an open framework that industry, regulators, and environmental groups can use.

3.2 Scope of Analysis

While a range of technologies and products that treat WW to different effluent standards were reviewed, the analysis portion of this work focuses primarily on the technologies that can essentially achieve drinking water quality. This high standard of treatment was chosen because it should be sufficient for reuse of the water for the majority of beneficial uses including discharge to surface water or land applications, such as livestock watering and irrigation.

Currently, operators who reuse treated WW do so mostly for the purpose of future well completions instead of other possible beneficial reuse options because 1) it often requires less water treatment than other options, 2) regulations sometime prohibit use of treated wastewater for other options, and 3) they have concerns around potential future liability with reusing for other beneficial purposes. Expanding the possible options for beneficial use could help reduce the volume of WW requiring disposal. Beneficial use options for treated WW are discussed in greater detail in Chapter 5.

The EPA's secondary maximum contaminant levels (MCL) for drinking water and the suggested recommendations on effluent quality set by the World Bank Group and the International Finance Corporation were used as the guidelines of acceptable water quality for this study [53, 54]. These establish stringent standards for both drinking and surface water quality.

The beneficial use of treated water depends heavily on its quality, nearby opportunities for reuse, and local, state, and federal regulations. The regulatory landscape for and liability concerns with reusing treated water from unconventional O&G activity is complicated and varies significantly by state and region. As such, the specific regulatory requirements necessary for treated water reuse for different applications in varying states is not addressed in this study. Regulatory agencies should be consulted before using treated water for beneficial purposes.

3.3 Methodology

Three main steps make up the overall methodology of this research objective:

1. Build a database of the many products and technologies available for WW treatment.

2. Design a WW treatment technology down-selection tool using a variety of inputs and metrics.

3. Apply the down-selection tool to compare and rank technologies based on water quality information in several shale regions.

Section 3.3.1 and Section 3.3.2 detail the work completed for steps one and two above. The third step is summarized in Section 3.4.

3.3.1 Wastewater Treatment Technology & Product Database

Building a framework for comparing and analyzing wastewater treatment options requires an evaluation of current and emerging technologies. As such, over 70 products and technologies that treat wastewater to varying effluent levels were evaluated and assessed using a diverse set of metrics that cover the technology's capability, logistics, finance, and maturity (described in Table 3.1). For each product or technology, information was obtained via literature reviews, corporate resources such as websites and whitepapers, conversations with technical and business development experts within the water treatment industry, as well as thermodynamic analysis of the treatment processes. A snapshot of the database is shown in Figure 3.2 and the entire database can be found in Appendix E. While not all metrics were directly incorporated into the resulting down-selection tool, each one informed the evaluation of the technologies.

WW often requires multiple treatment steps to remove the variety of constituents it contains. The amount of treatment that is needed depends heavily on both the starting WW quality (i.e., the WW constituents and their concentrations) and the desired end-use for the treated water. Figure 3.1 illustrates possible water treatment steps depending on the desired ending water quality and Table 3.2 summarizes the various common WW constituents found in HF WW.

The treatment technologies and products are classified in the database by treatment type and, in general, fall into the following categories: primary treatment, oxidation and disinfection, filtration, tertiary treatment, and removal of naturally occurring radioactive material (NORM). Primary treatment (sometimes termed pretreatment) is often the first and most basic treatment to remove suspended solids via mechanical processes, such as corrugated plate interceptors and centrifuges. Ox-

Table 3.1: The 15 metrics used to assess each evaluated technology's or product's capability, logistics, finance, and maturity. Information for the metrics was obtained via literature reviews, conversations with industry experts, and corporate resources.

Category	Metric	Description
Capability	Maximum throughput or capacity	Volume of WW the treatment system can process per unit time
	Feed Water (influent) quality	Concentration of the constituents present in WW
	Treated water (effluent) quality	Concentration of the constituents remaining after processing through treatment system
	Constituents removed	Constituents the system removes from the WW
	Recovery Rate	The ratio of the volume of effluent (treated water) to volume of influent (WW)
Logistics	Consumables	Chemicals, additives, or other products (including hazardous materials) required
	Energy requirements	Energy required (and in what form) per unit of influent
	Mobility	Ability to move the system from one location to another
	Personnel Requirements	Number of employees and other support staff needed to run and maintain the system
	Applicable regions	Feasible regions to implement the system
	Waste stream	Volume and quality of the remaining waste stream from the system
	Hardware downtime or shutdown	Length of time and frequency the system needs to undergo maintenance
	Lifetime of hardware	Length of time the system and its parts are expected to last
Finance & Readiness	Technology Readiness Level (TRL)	Maturity level of the technology
	Service fees or CAPEX[1] & OPEX[2]	The cost to either use the system on a per volume basis or cost to purchase and run system

[1] CAPEX stands for Capital Expenditures and represents costs associated with procuring equipment.
[2] OPEX stands for Operating Expenses and represents ongoing costs associated with the equipment such as electricity or energy costs, salaries, etc.

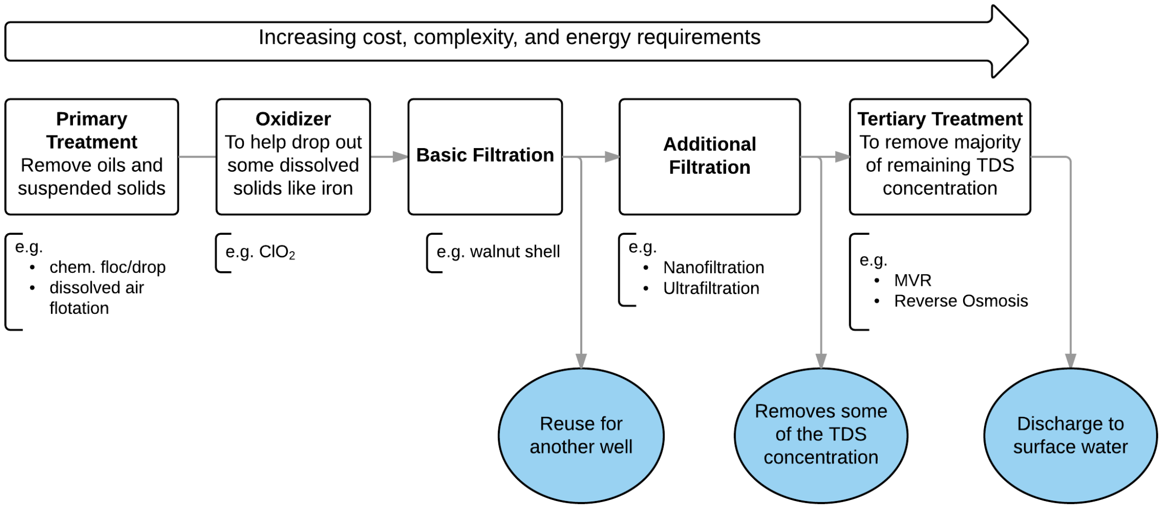

Figure 3.1: Summary of the potential treatment steps required for achieving differing levels of effluent water quality. The cost, complexity, and energy requirements increase as more constituents are removed.

idation and disinfection help with iron removal and controlling bacteria using, for example, ultraviolet inactivation or chlorine dioxide. TDS concentration is significantly reduced during tertiary treatment to levels often lower than 500 mg/ℓ, the standard set by the EPA in their secondary MCL for drinking water; examples include distillation and reverse osmosis [53].

To achieve drinking water quality, the majority of the dissolved solids must be removed. As such, the focus of this objective was primarily on desalination technologies generally capable of treating WW with high TDS concentrations. While TDS alone does not completely represent water composition, its concentration is used as a conventional benchmark of water quality and is regularly one of the most difficult and energy intensive components to remove from water. Once wastewater has been sufficiently treated to achieve ultralow TDS levels, other constituents of interest have likely already been removed.

Table 3.2: Common constituents in hydraulic fracturing wastewater and common treatment technologies or options that can remove them.

Constituent Type	Description	Example Constituents	Example Treatment Options
Suspended Solids	Particles in WW that do not settle out and remain undissolved	hydrocarbons, organic matter, colloids, granular material from formation, biological material	centrifuges, filters
Dissolved Solids	Constituents that dissolve into the WW (often ionic compounds)	sodium chloride and other salts	distillation and reverse osmosis
Dissolved Gases	Gases dissolved in solution many of which are hazardous and must be handled properly	carbon dioxide, hydrogen sulfide, benzene, toluene, methane	air stripping
Metals	Mineral species such as calcite, halite, barite, and iron sulfides can cause scaling on water management equipment, pipes, wells, and formations	iron, manganese, lithium	oxidation with chlorine dioxide or ozone
Bacteria	Living matter can cause damage to equipment and impair well characteristics by clogging or fouling	bacteria & microorganisms	disinfectants, ultraviolet radiation
NORM	Naturally Occurring Radioactive Material	radium-226 & radium-228	filter socks

Technology Name	Altelarain 750	MoVap System	Mobile Frac Evaporator
Technology Type	Thermal distillation	MVR	MVR
Vendor/Owner	Altela Inc	Aquatech	GE
Capacity, m3/d	119	290, scaleable	275
Mobility	stationary	mobile	mobile
Costs $/bbl	$5.29/bbl, 4.88/bbl for OPEX. Contacted but was unwilling to provide information unless we disclosed clients and other technologies we're investigating.	Service: $6-7/bbl (job-specific approach), energy: $0.30-0.40/bbl	Contacted and following up
Feed water quality, ppm	--	≤140,000 TDS	50000-150000 TDS; low sulphate, oil, iron, manganese; <100 TSS
Treated water quality, ppm	<250 TDS	<500 TDS	TDS: <50 mg/L; Non-volatile organics: <1 mg/L
Waste fraction,v/v%	0.1	feed: 130-140,000 TDS - 50%, 30-50,000 TDS - 70%	Dep on feed TDS; brine <285 000 TDS; 5%
Consumables	Polypropylene plastic	Anti-scalant	Acid, caustic for CIP
Power supply	460V 3-phase @ 65 RLA/75 FLA; 110V single phase @ 15 RLA/60 FLA; 120 MCF of natural gas and 1400 kWh of electricity per 24 hour day	300-350 horsepower	295 kWh at feed 30oC
Technology Readiness Level (TRL)	--	7	--
Current Region of Operations	--	Permian Basin, Pennnsylvania	--
References/Notes	Brochure on AltelaRain 750 - reuses latent heat of condensation	Pretreat with MoTreat and/or MoFeed. Water has been processed by MoTreat and MoFeed to yield service conditions: pH = 5.0 - 8.0; chlorides = 25,000 - 100,000 ppm; TDS = 5 - 12%; TSS < 50 ppm	--

Figure 3.2: Snapshot of three tertiary treatment products in the database. The contents of the entire database as of the published date of this dissertation can be found in Appendix E.

The process of treating O&G WW will also produce a waste stream, often a more concentrated, highly saline solution, slurry, or solid [55]. When this waste stream is still in liquid form it is often termed "concentrated brine" or just "brine." This waste stream is often disposed of, however, in some cases there could also be beneficial reuses for it. For instance, in the process of treating wastewater, a "10 pound" brine can be produced that could be used during maintenance and management of current or future wells. Ten pound (or 10 ℓb) brine is a solution that contains 230,000 to 260,000 mg/ℓ TDS concentration, resulting in a fluid with a density of approximately 10 ℓb/gal. In certain shale regions, such as the Eagle Ford, this type of waste stream can be a valuable commodity sold to other operators for shutting in wells. In some regions, concentrations of certain valuable constituents might be high enough to consider extraction. For example, lithium, a key mineral in lithium-ion batteries, is sometimes found in produced water from shale formations at concentrations that could make extraction technically and economically feasible [56].

3.3.2 Treatment Technology Down-Selection Tool

To match the technologies or products for a particular operation, a down-selection tool was built in which each technology was graded for relevant performance metrics. The seven metrics used to compare technologies were technology readiness level (TRL), mobility, influent quality, effluent quality, waste stream, energy intensity, and cost as shown in Table 3.4. TRL is based on a scale originally developed by NASA and then adopted by the American Petroleum Institute to estimate the maturity level of a technology or program [1, 2]. These seven metrics were chosen (from the 15 evaluated and listed in Table 3.1) to populate the tool because, according to industry experts consulted, they are often the most important considerations to operators. However, if an operator deems another metric more important the tool can be updated accordingly.

It should be noted that the down-selection tool is designed to compare and rank products and technologies from the same treatment category and for wastewater from a specific shale region. For example, tertiary treatment technologies should be compared to other tertiary treatment technologies and not against primary technologies since they tackle different wastewater quality, remove different constituents, and require widely divergent amounts of energy, among many other differences. In addition, regional differences such as wastewater quality, water availability, wastewater disposal access, geology, among others, could mean certain technologies are better suited for one area over another. As such, the down-selection tool should be used to compare and rank technologies for one shale region at a time.

The next critical element of the down-selection tool is assigning a weighting to each metric. This weighting value indicates the metric's relative importance in the down-selection process. The weighting across all metrics should total 100%. For example, if TRL is given a weighting of 0.2 (20%), then the remaining metrics weighting should sum to 0.8 (80%).

As mentioned, this study focused mainly on comparing tertiary treatment technologies so that the final water quality would contain very low concentrations of TDS ($<$500 mg/ℓ). Of the over 70 products, seven tertiary treatment technologies were evaluated, summarized in Table 3.3, due to their capability of treating water to TDS concentrations of less than 500 mg/ℓ.

The down-selection process was further guided by both quantitative and qualitative metrics, such as energy requirements and mobility, respectively. MSF and MED were eliminated because they often require large, immobile facilities and have not seen much implementation for treating O&G wastewater [55]. FO was eliminated

Table 3.3: Summary of the seven tertiary treatment technologies evaluated in this study. Additional details on these technologies can be found in Appendix A.

Technology	Acronym	Description
Mechanical Vapor Recompression	MVR	Vaporizes influent water and passes it through a compressor and into an evaporative heat exchanger
Multi-Effect Distillation	MED	Boils feed water to produce steam, which is then condensed
Multi-Stage Flash Distillation	MSF	Heats water and then uses flash evaporation
Carrier Gas Exchange	CGE	Heats wastewater and sprays it into a column with crumpled material to evaporate
Reverse Osmosis	RO	Passes water through a membrane and selectively removes ions
Membrane Distillation	MD	Draws water through a membrane using a vapor pressure gradient to separate pure water from wastewater
Forward Osmosis	FO	Separates water from dissolved solutes by passing wastewater through a semi-permeable membrane

Table 3.4: The down-selection tool compares multiple technologies across a set of seven metrics and takes into consideration the needs of the operator, as well as the regional characteristics, such as the quality of the wastewater. A column should be included in the table for each technology being compared and ranked. The weightings can be modified and applied to different cases.

		Technology Name		
Metric	Weighting	Factor	Grade	Max. Value
TRL	0.XX			
Mobility	0.XX			
Influent Quality	0.XX			
Effluent Quality	0.XX	Value out of 7	Weighting × Factor	Weighting × 7
Waste Stream	0.XX			
Energy Intensity	0.XX			
Cost/Service Fee	0.XX			
Total	1.00		Sum of grades	7.00

because at the time of this study was still too early stage to be properly assessed for its potential for treating O&G WW in the field [55]. This process narrowed the list of seven tertiary technologies viable in oil and gas production at the time of this study to four viable ones: MVR, RO, MD, and CGE. Note that improvements to MSF, MED, FO, and other technologies might change their viability for future operations, in which case the same framework could still be used to assess their suitability.

Next, a factor value was assigned for each technology for each metric. The factor value range is from 1 to 7 with a higher value corresponding to a more favorable ranking for the technology. A range of 1 to 7 was chosen to align with the TRL ranking system [2]. As an example, TRL for MVR was assigned a factor of 7 indicating that it is commercially available. By comparison, MD received a factor value of 1 since it is still an early stage technology in the research and development phase for this application. Table B.1 in Appendix B provides descriptions for each factor value within TRL.

In the down-selection tool, each weighting was then multiplied by the technology-specific factor to obtain a grade for that metric (shown in Table 3.4). The sum of the grades can be determined once each metric for a technology has a grade calculated. As a point of reference, the highest total grade a technology could receive is 7.

This system of weighting the various metrics allows for a quantitative, side-by-side comparison of the different technologies with respect to the metrics of interest. Appendix B details each metric and the descriptions for each of the factor values. The weighting and factors can be adjusted in the tool for different shale regions with varying wastewater qualities to compare the performance of treatment technologies.

To summarize, over seventy products and technologies (listed in Appendix E) were reduced to seven key tertiary technologies for deeper investigation (described in Table 3.3 and Appendix A). Of those seven tertiary technologies, four were determined to be currently viable and ranked based on wastewater quality from various regions (shown in Tables 3.5-3.7). Furthermore, the fifteen metrics used to evaluate all the technologies (detailed in Table 3.1) were reduced to seven key metrics implemented in the down-selection tool.

3.4 Results and Discussion

For this study, an industry collaborator provided water quality and quantity data from the Eagle Ford in Texas, Marcellus in the northeast, and Bakken in North Dakota. Since the focus was to select appropriate tertiary technologies, the average TDS concentration for these three regions were used to compare the technologies. That said, the down-selection tool was not applied for the Bakken WW since its average of 260,000 mg/ℓ TDS concentration eliminates the majority of currently available treatment options. Knowledge on the Niobrara region was also used to further illustrate the down-selection tool's capabilities.

Table 3.5 and Table 3.6 use the down-selection tool to compare technologies to treat wastewater produced in the Eagle Ford and Marcellus shale regions, respectively. The Marcellus region has relatively low flowback and produced water volumes and high TDS concentration (135,000 mg/ℓ) compared to the Eagle Ford shale, which has an average TDS concentration of 48,000 mg/ℓ. In addition, the Eagle Ford shale has an arid climate and is often water-stressed. While the Marcellus has sufficient water resources, it has very few disposal wells available, which means wastewater requiring disposal is often trucked long distances resulting in significantly higher disposal costs compared to the Eagle Ford region.

When applying the tool to both regions, these differences are taken into account when assigning the factor to each metric. For this comparison, specifically the metric *Influent Quality* is considered differently for each. For example, RO is not ideal for handling wastewater with a TDS concentration higher than 50,000 and thus is not a viable option for the Marcellus. Therefore, it is given a factor of 1 for the Marcellus, compared to the factor of 4 given to RO for the Eagle Ford, whose lower TDS concentration makes RO a possibility. Similarly, for the Marcellus, the factor assigned to *Influent Quality* is lower for CGE and MD compared to that for the Eagle Ford due to these technologies' inability to handle high TDS concentrations. For both shale regions, MVR is assigned the highest factor for *Influent Quality* due to its ability to handle a wide range of TDS concentrations in wastewater.

Even with regional characteristics considered in the down-selection tool, MVR received the highest overall grade for both the Eagle Ford and Marcellus shale areas. MVR's high score in the down-selection tool for both regions is mainly due to the fact that 1) TRL, Mobility, and Influent Quality are weighted heavily compared to most of the remaining metrics and 2) MVR received a factor of 7 for each of these three metrics.

It is also worth noting that while the ranking order of the technologies was the same for both regions (i.e., MVR followed by CGE, RO, and MD), the grades the technologies received varied by region. That is, MVR outranked CGE (the second highest ranked technology) in the Eagle Ford 5.6 to 4.55 compared to the greater difference in grades seen in the Marcellus of 5.6 to 3.95. This outcome suggests that CGE is likely more feasible in the Eagle Ford than the Marcellus.

Table 3.5: A comparison of the treatment technologies using the down-selection tool for wastewater produced in the Eagle Ford shale region with TDS levels of approximately 40,000 mg/ℓ [31]. The factors used for the down-selection tool are described in greater detail in Appendix B.

		MVR		RO		CGE		MD		
Metric	Weighting	Factor	Grade	Factor	Grade	Factor	Grade	Factor	Grade	Max. Value
TRL	0.20	7	1.40	4	0.80	4	0.80	1	0.20	1.40
Mobility	0.15	7	1.05	4	0.60	4	0.60	7	1.05	1.05
Influent Quality	0.20	7	1.40	4	0.80	7	1.40	7	1.40	1.40
Effluent Quality	0.05	7	0.35	7	0.35	7	0.35	7	0.35	0.35
Waste Stream	0.20	3	0.60	3	0.60	3	0.60	3	0.60	1.40
Energy Intensity	0.10	4	0.40	7	0.70	4	0.40	1	0.10	0.70
Cost/Service Fee	0.10	4	0.40	4	0.40	4	0.40	4	0.40	0.70
Total	1.00		5.60		4.25		4.55		4.10	7.00

The down-selection tool can be modified by altering the assigned weighting, the factor values given, and the technologies considered. With these changes, the tool can be used to compare WW treatment technologies in a shale region while taking the characteristics of that region into consideration. In addition, the needs of the operator can be taken into account when altering the tool. For example, Table 3.7 uses alternate weightings based on the needs of an operator in the Niobrara region. Rather than prioritizing immediate implementation, an operator may be more concerned with energy intensity due to the lack of access to grid power in the region,

Table 3.6: A comparison of the treatment technologies using the down-selection tool for wastewater produced in the Marcellus shale region with TDS level of approximately 130,000 mg/ℓ [32].

		MVR		RO		CGE		MD		
Metric	Weighting	Factor	Grade	Factor	Grade	Factor	Grade	Factor	Grade	Max. Value
TRL	0.20	7	1.40	4	0.80	4	0.80	1	0.20	1.40
Mobility	0.15	7	1.05	4	0.60	4	0.60	7	1.05	1.05
Influent Quality	0.20	7	1.40	1	0.20	4	0.80	1	0.20	1.40
Effluent Quality	0.05	7	0.35	7	0.35	7	0.35	7	0.35	0.35
Waste Stream	0.20	3	0.60	3	0.60	3	0.60	3	0.60	1.40
Energy Intensity	0.10	4	0.40	7	0.70	4	0.40	1	0.10	0.70
Cost/Service Fee	0.10	4	0.40	4	0.40	4	0.40	4	0.40	0.70
Total	1.00		5.60		3.65		3.95		2.90	7.00

thus making them reliant on onsite generators. As such, energy intensity is given the greatest overall weighting, while TRL is given the smallest. In addition, the Niobrara regions water has a relatively low TDS concentration (approximately 25,000 mg/ℓ); since all technologies are capable of treating wastewater at that concentration, the influent quality weighting can be lower. After adjusting the weightings to match these considerations, reverse osmosis (RO) came away with the highest overall grade. While MVR received the highest grade for the Marcellus and Eagle Ford, its high energy intensity makes it less favorable than RO for the Niobrara region.

3.5 Takeaways

The overall goal of this research objective was to develop a framework for matching appropriate treatment technologies with wastewater from unconventional oil and gas sites. Over 70 water treatment technologies and products were analyzed to develop a database (see Appendix E) that informed the creation of the down-selection tool. The products and technologies were compared based on metrics such as mobility, energy intensity, and capability of handling highly saline influent wastewater. A framework and tool were built to guide a down-selection process of the different

Table 3.7: A comparison of technologies for treating wastewater produced in the Niobrara shale region with an average TDS concentration of 25,000 mg/ℓ [57]. This case prioritizes energy intensity, resulting in reverse osmosis receiving the highest grade.

		MVR		RO		CGE		MD		
Metric	Weighting	Factor	Grade	Factor	Grade	Factor	Grade	Factor	Grade	Max. Value
TRL	0.05	7	0.35	4	0.20	4	0.20	1	0.05	0.35
Mobility	0.15	7	1.05	4	0.60	4	0.60	7	1.05	1.05
Influent Quality	0.10	7	0.70	7	0.70	7	0.70	7	0.70	0.70
Effluent Quality	0.10	7	0.70	7	0.70	7	0.70	7	0.70	0.70
Waste Stream	0.20	3	0.60	3	0.60	3	0.60	3	0.60	1.40
Energy Intensity	0.30	4	1.20	7	2.10	4	1.20	1	0.30	2.10
Cost/Service Fee	0.10	4	0.40	4	0.40	4	0.40	4	0.40	0.70
Total	1.00		5.00		5.30		4.40		3.80	7.00

water treatment technologies. Using this methodology, it was determined that the most suitable water treatment technology for generating water with ultralow TDS concentration is currently MVR in most regions. However, exceptions exist such as RO in the Niobrara region. Technologies such as MD and CGE should be re-evaluated in the future to determine whether improvements have been made that would make the alternate technologies more competitive with MVR.

To maintain its relevance in this space, the technology database should be updated to reflect improvements made to current and emerging technologies, when new technologies come into existence, when technologies are discontinued, or companies go out of business. Furthermore, the database does not claim to capture all possible technologies and products available.

Chapter 4

Technical Potential for Using the Energy from Flared Natural Gas to Power Wastewater Treatment in the Major Shale Regions in the US

4.1 Introduction

While Objective 1 in Chapter 3 focused solely on wastewater, this objective investigates both wastewater and associated natural gas flaring, two major waste streams connected with unconventional O&G activity. Along with the significant water required for well completion, these are the most prominent environmental liabilities often associated with unconventional O&G activity. While all three environmental challenges (significant water use, flaring, and wastewater generation) are present in most shale regions, their impact and severity on a regional and local level depend on a variety of factors including the geology of the shale formations, prevailing climate conditions, access to freshwater resources, access to nearby saltwater disposal (SWD) sites, existing pipeline infrastructure, and state regulations, among other factors.

In regions where both oil and gas are produced, operators will sometimes flare some portion of the produced associated natural gas onsite rather than venting it or delivering it to market. Flaring natural gas can be the response to varying spatial and

This chapter was adapted from the journal paper: Y. R. Glazer, F. T. Davidson, J. J. Lee, and M. E. Webber, An Inventory and Engineering Assessment of Flared Gas and Liquid Waste Streams From Hydraulic Fracturing in the USA, *Current Sustainable/Renewable Energy Reports*, vol. 4, pp. 219231, 2017 [58]. The majority of the journal article's data curation, data analysis, and writing were done by the author of this dissertation.

temporal conditions including changes in well conditions that might create a safety hazard or the lack of sufficient natural gas gathering and transmission infrastructure.

To the author's knowledge, no prior work in the archival literature compiles and curates both the volumes of WW and flared gas (FG) by shale region in the US into an integrated study. This objective seeks to fill that gap as understanding the volumes and magnitudes associated with these two waste streams and their variability by region is vital to mitigating them.

In addition, whether sufficient energy was flared during the years 2012 through 2014 to treat the generated WW in each respective region was investigated. If the FG was repurposed as a source of energy for WW treatment, then the volume of WW requiring disposal could have been reduced, the natural gas that would otherwise be wasted could have been put to beneficial use, and treated water (TW) that could be used for beneficial purposes could have been generated, thereby solving multiple problems simultaneously. The author's previous study used extensive datasets and engineering models to assess the potential to use the energy from FG for onsite treatment of HF WW in Texas and concluded that, in 2012, Texas flared enough natural gas to generate 180—540 million m^3 (46—140 billion gallons) of TW, representing 12.4% of total statewide water demand for all purposes [44]. These results, along with the knowledge that many operators in shale regions across the US grapple with these environmental issues, motivated the expansion of this work to evaluate these waste streams on a national level for multiple major shale regions.

In light of trends such as rising WW treatment and reuse in many shale regions and new regulations scheduled to limit natural gas flaring, the approach analyzed here could help mitigate continued flaring of associated natural gas and WW disposal while generating a valuable commodity of treated water that could help avoid extensive freshwater or ground water sourcing.

This study closely examines the years prior to the significant drop in oil prices around 2015. The dramatic decline in oil prices changed many operating practices in the oil and gas field that led to decreased volumes of FG as the rig count declined in some regions (e.g., in the Bakken) and potential increases in water injection volumes per well as longer laterals were used to increase productivity on a per well basis (e.g., in the Permian Basin). Despite changes since 2015, the waste streams of FG and WW remain significant; this work intends to provide historical context for future operations by investigating FG and WW production over the period of 2012 to 2014.

4.2 Shale Regions of Interest

Seven shale regions representing the vast majority of growth in oil and gas operations in the US during the decade leading up to 2015 were chosen for this study: Permian Basin, Eagle Ford, Haynesville, Marcellus, Utica, Niobrara, and Bakken (shown in Figure 4.1). Together, these regions made up 56% of total oil production and 50% of total natural gas production in the US in 2015 and made up more than 90% of new growth in oil and gas production in the US between 2011 and 2014 [59]. The Permian Basin, Eagle Ford, and Bakken are key regions for shale oil production, having produced 20, 17, and 13% of total domestic oil production in 2015, respectively. The Marcellus is the dominant shale gas producer, having supplied an average of 480 million m^3/day (16,800 million ft^3/day) of natural gas in 2015, the equivalent of almost 19% of total domestic gas production [59].

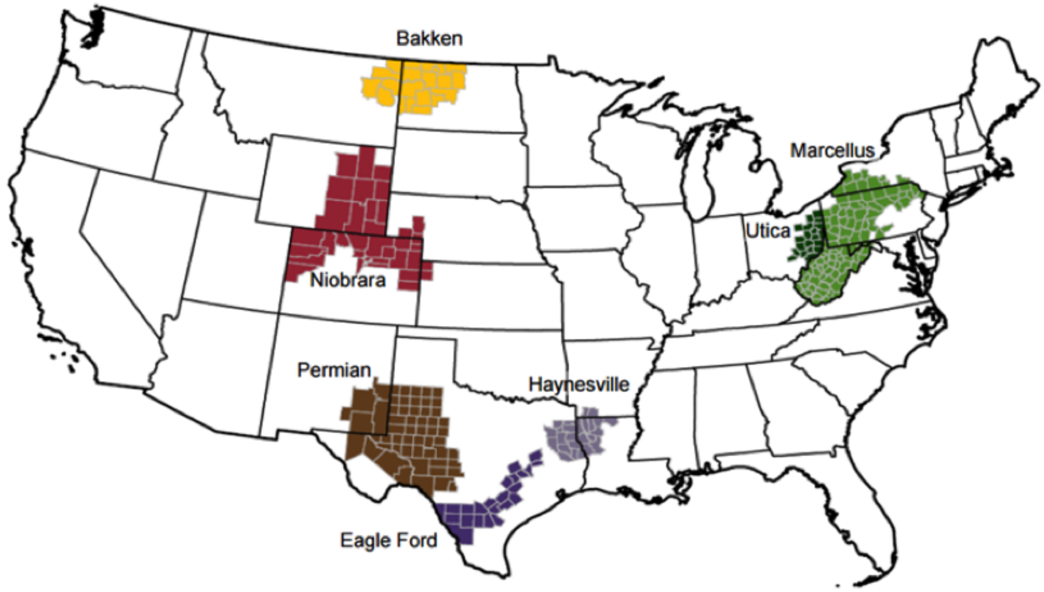

Figure 4.1: Map from the *EIA Drilling Productivity Report* showing the location of the seven shale plays investigated in this study [7].

4.3 Data

4.3.1 Data Acquisition

The data were compiled and curated for each shale region mainly from state agencies' oil and gas division websites and databases, and spot-checked with industry data when possible. To the author's knowledge, the necessary data to perform an analysis resolved by each shale region had not been synthesized, curated, nor available in one centralized location prior to this work. This process proved challenging and tedious as there was little consistency in how data were presented or reported across different state agency websites. This inconsistency is due to the fact that many rules and regulations related to O&G practices are mandated on a state level. As such, each state implements their reporting requirements differently and some states do not currently require operators to report some information. For example, at the time of this study, Pennsylvania did not publish flared gas volumes directly. Instead, emissions due to natural gas operations are provided as an annual value broken down by source [60]. At the time of this study, only 2012 and 2013 emissions data were available in Pennsylvania. By comparison, Colorado published monthly FG volumes by county while North Dakota listed statewide FG volumes but did not separate the data by county [24, 61]. North Dakota did, however, identify FG volumes for the Bakken region, specifically. Similar types of inconsistencies existed for both well completion and produced water volume data across the various states.

Twelve states were considered for this analysis, spanning the seven shale plays of interest, since many plays cross state lines. In addition, where possible, data over multiple years, 2012 through 2014, were obtained to see if any trends could be observed over the three-year period.

Preferably, data on the volume of WW generated, quality of the WW, and volume of FG would be available on a per-well basis with a daily, or even hourly, time resolution. Such data would likely make it possible to understand whether enough FG is available for WW treatment on a near real-time basis and the level of treatment required based on the initial WW quality. Where data are available, the time resolution was often at best monthly. In addition, available data often do not clearly differentiate between the source location of the FG and the source location of the WW. This absence means that there is uncertainty regarding whether the primary sources of FG coincide with the primary sources of WW. As a result of the low spatial resolution, the volumes of WW and FG were aggregated for each respective shale region. However, the data herein is still more finely resolved than state-level aggregations that have been reported in prior work [46].

4.3.2 Data Curation

Several significant complications with data acquisition were encountered including the following:

1. not all states require operators to report the data of interest;
2. some states do not separate their well information based on formation;
3. many state agency websites have limited online resources allowing for data to be downloaded and aggregated;
4. the data are sometimes labeled vaguely, leaving room for interpretation on their meaning; and
5. the data available are not always complete.

Table 4.1 provides a summary of data availability for each state of interest. The data collected and curated for this study were as follows: (1) the number of wells completed, (2) the volume of water used for HF, (3) the volume of WW generated, and (4) the volume of FG for each region. Where data are listed as not found or not currently tracked, multiple attempts were made to obtain data by contacting the appropriate state agencies. In addition, subject matter experts were also contacted to provide additional clarification when the labeling of reported data was deemed vague. In limited cases, state data that were not easily available online were sent via email (e.g., data from Ohio and Louisiana). In other cases, the state agency confirmed that the desired data were unavailable or open record requests would be required to access the relevant documents. The following states were excluded from this study due to lack of available and accessible data or low well completion counts in the relevant shale plays: Montana, West Virginia, Ohio, Wyoming, Nebraska, Kansas, Louisiana, and New Mexico.

All states included in this study require operators to disclose their chemical use, which often means that the operators also disclose water volumes for HF. All but two of the states (Wyoming and New Mexico) require operators to report this information to FracFocus, an online database of operator-reported frac fluid constituents that also includes location, and volume of water injected for each well.

Data for the Marcellus and the Utica shale formations were combined and considered as one region because the state agencies of interest, primarily Pennsylvania, do not categorize the WW or FG data by the formation from which they originated.

While the WW quality is not central to this study, it plays a key role in understanding the possible treatment options that are technically feasible and whether treatment should even be considered. In some regions, the WW quality is so poor that treatment is likely unrealistic from an economic standpoint given currently available treatment options. The dirtier the WW, the lower the recovery rate (the fraction of TW compared to initial WW volume). Thus, as WW quality decreases so does the economic viability of WW treatment.

To the author's knowledge, no states required detailed reporting of the WW quality. Therefore, the concentration of TDS in the WW as a proxy for WW quality was used. TDS concentration was used because removal of dissolved constituents via tertiary treatment technologies is often the most energy intensive step during WW treatment [37]. As a result, the TDS concentration is often the driving factor for how much energy must be expended to treat the WW. Other constituents should also be accounted for when fully defining the quality of a given water sample. The average TDS concentrations used to guide this study are provided in Table 2.1.

Shale Region	Associated States	Year	Number of completed wells	Water Injected Volume	Wastewater Volume	Flared Gas Volume
Bakken	North Dakota	2012	●	●	●	●
		2013	●	●	●	●
		2014	●	●	●	●
	Montana	2012	▲	●	◆	▲
		2013	▲	●	◆	▲
		2014	▲	●	◆	▲
Marcellus & Utica	Pennsylvania	2012	●	●	●	●
		2013	●	●	●	●
		2014	●	●	●	◆
	Ohio	2012	●	●	●	◆
		2013	●	●	●	◆
		2014	●	●	●	◆
	West Virginia	2012	●	●	◆	◆
		2013	●	●	◆	◆
		2014	●	●	◆	◆
Eagle Ford	Texas	2012	●	●	●	●
		2013	●	●	●	●
		2014	●	●	●	●
Niobrara	Colorado	2012	●	●	●	●
		2013	▲	●	●	●
		2014	▲	●	●	●
	Wyoming	2012	●	●	●	●
		2013	●	●	●	●
		2014	●	●	●	●
	Nebraska	2012	●	●	●	◆
		2013	●	●	●	◆
		2014	●	●	●	◆
	Kansas	2012	◆	●	◆	◆
		2013	◆	●	◆	◆
		2014	◆	●	◆	◆
Haynesville	Texas	2012	●	●	●	●
		2013	●	●	●	●
		2014	●	●	●	●
	Louisiana	2012	●	●	■	■▲
		2013	●	●	■	■▲
		2014	●	●	■	■▲
Permian Basin	Texas	2012	●	●	●	●
		2013	●	●	●	●
		2014	●	●	●	●
	New Mexico	2012	◆	●	▲	◆
		2013	◆	●	▲	◆
		2014	◆	●	▲	◆

Table 4.1: This table shows whether the relevant data (including number of wells completed, volume of water used for well completion, volume of WW generated, and volume of FG) were available for the regions of interest. Green circles represent data were found. Red diamonds represent data are incomplete (e.g., state agency tracks but is backlogged so value is not most up-to-date/accurate, state collects but doesn't separate by formation). Purple triangles signify no data were found nor currently tracked. Blue squares signify data are collected but not made easily accessible (e.g., on microfilm in state agency office, not online).

4.4 Wastewater Treatment Options

There are many potential WW treatment technologies as discussed in detail in Chapter 3 and listed in Appendix E. From a technical standpoint, choosing the appropriate technologies depends primarily on the WW quality and quantity and the desired use for the TW (i.e., the desired quality of the TW). As discussed in Chapter 3, several treatment steps are often required to remove the various constituents present in WW [37]. This study focused on the treatment technologies capable of reducing the TDS concentration. Specifically, mechanical vapor recompression (MVR) was chosen as the benchmark technology to conduct this engineering assessment for several reasons, including: 1) it is a technology that can treat high TDS concentrations common with WW, 2) the resulting high quality TW (effluent) affords the operators many options for beneficial reuse, 3) it is currently used for WW treatment at oil and gas sites suggesting it has sufficient technical maturity, 4) based on interviews with multiple industry experts, it appears to be the current industry standard when treating high-salinity oil and gas WW to achieve high-quality effluent, and 5) it was determined in Research Objective 1 to be the best treatment option in most shale regions when high effluent quality is desired [62]. However, many technologies are under development, so it is likely that in coming decades, new treatment approaches will be implemented. While MVR and other distillation techniques are often preceded by primary treatment steps, such as chemical precipitation and coarse filtration, the energy intensity of these steps are not included in this analysis as they are often much less by comparison [36, 37, 62]. As such, the energy intensity of MVR serves as a benchmark in this study to assess the amount of energy that would be required to treat the volume of WW in each region.

4.5 Analytical Methods

The energy density of the FG is not constant due to the regional variability in natural gas composition across shale formations. For example, the natural gas produced in the Bakken has a higher energy density compared to other regions due to the higher percentage of natural gas liquids (NGL) such as ethane, butane, and propane [63]. The total primary energy in the FG is:

$$E_{FG}[MJ] = 38.3 \left[\frac{MJ}{m^3 of natgas} \right] \times \rho_{ED} \times V_{FG}[m^3] \tag{4.1}$$

where V_{FG} is the volume of FG and ρ_{ED} is an energy density normalization factor that relates the actual energy density of the gas to the US pipeline standard. For the purpose of this analysis, ρ_{ED} was set to unity, reflecting an assumption that the FG is pipeline quality natural gas and contains approximately 38.3 MJ/m^3 (1028 BTU/ft^3) [64]. FG containing high fractions of inert gases would have a lower energy density and, in such cases, ρ_{ED} should be reduced below unity. While this work uses unity for illustrative purposes, future work could use the same analytical expression to consider a wider range of values for the energy density of FG.

The recovery rate (i.e., fraction of TW to total WW generated), estimated and listed in Table 4.2, varies by region and depends on the TDS concentration of the WW. For all regions, it was assumed that MVR removes essentially all of the TDS concentration from the TW and generates a concentrated brine of 265,000 mg/ℓ TDS (approximately 10-ℓb brine). The volume of treated water in a region is described as:

$$V_{TW}[m^3] = F_{recovery} \times V_{WW}[m^3] \tag{4.2}$$

a function of the expected recovery rate for the region, $F_{recovery}$, and the total wastewater volume in that region, V_{WW}. The amount of equivalent primary energy required to generate TW using MVR is:

$$E_{TW}[MJ] = \frac{e_{MVR}\left[\frac{MJ}{m^3}\right] \times V_{TW}[m^3]}{\eta} \tag{4.3}$$

a function of V_{TW}, the energy intensity of MVR, e_{MVR}, and the efficiency of the generator, η. This analysis incorporates a model of an onsite reciprocating engine generator with a thermal efficiency of $\eta = 35\%$ to produce the electricity for driving the compressor. An energy intensity of $148 MJ/m^3$ (530 BTU/gal) of TW is used as an estimation for the MVR process based on available data from literature and interviews with existing operators of MVR units [65,66]. Additional parasitic losses, such as pressure drop in system pipelines, were not included in this analysis.

The energy surplus ratio, E_{FG}/E_{TW}, was calculated for each region for each year (where data were available) and is included in Table 4.2. This ratio helps reveal the magnitude of wasted FG energy compared to the energy requirements for treatment. If the energy surplus ratio is less than one, there would not be enough energy in the aggregated FG to treat all of the WW in the region, in which case additional energy resources (from grid-tied electricity or extracted oil and gas, for example) would be necessary for WW treatment. A ratio of greater or equal to one suggests that there would be enough energy in the FG alone to treat all of the WW generated in the region.

Table 4.2: Summary of 1) the curated data including number of completed wells, WW, and FG volumes, 2) the estimated recovery rates for MVR, and 3) the calculated values for E_{FG} and E_{TW}, and the ratio E_{FG}/E_{TW} for the seven shale regions for 2012 through 2014. Data on FG volumes were not available for 2014 in Pennsylvania at the time of this study.

Shale Region/ Associated State	Year	Number of Completed Wells	Total Volume of WW (10^6 m^3)	Total Volume of FG (10^6 m^3)	Recovery Rate of MVR (%)	Energy of FG (PJ)	Energy for WW Treatment (PJ)	Enough FG for WW Treatment?	Ratio: Energy of FG to Energy Required for WW Treatment
Notation			V_{FG}	V_{TW}	$F_{recovery}$	E_{FG}	E_{TW}		E_{FG}/E_{TW}
Bakken/ North Dakota	2012	2,010	41.9	2,120	10	81	1.8	Yes	45.0
	2013	2,183	51.6	2,730		105	2.2	Yes	47.7
	2014	2,353	64.9	3,380		129	2.7	Yes	47.8
Marcellus Utica/ Pennsylvania	2012	2,373	4.5	570	50	22	0.9	Yes	24.4
	2013	2,174	5.5	449		17	1.2	Yes	14.2
	2014	2,164	6.9	N/A		N/A	N/A	N/A	N/A
Eagle Ford/ Texas	2012	4,053	240.4	542	85	21	86	No	0.2
	2013	6,258	252.6	1,060		41	91	No	0.5
	2014	6,379	258.3	1,100		42	93	No	0.5
Niobrara/ Colorado	2012	2,751	2.9	147	90	6	1.1	Yes	5.1
	2013	591	3.3	160		6	1.2	Yes	5.1
	2014	80	5.2	102		4	2.0	Yes	2.0
Haynesville/ Texas	2012	633	50.6	15	55	0.6	12	No	0.1
	2013	523	48.0	17		0.7	11	No	0.1
	2014	465	53.2	5		0.2	12	No	0.0
Permian Basin/ Texas	2012	6602	660.2	233	50	9	140	No	0.1
	2013	3,677	686.4	621		24	140	No	0.2
	2014	8,415	752.0	920		35	160	No	0.2

4.6 Results and Discussion

The curated data for WW and FG volumes, the calculated values for E_{FG} and E_{TW}, and the energy surplus ratio for each shale region investigated are summarized in Table 4.2. It should be noted that the information provided in this table only includes data from states listed under 'Associated States'. For example, while the Bakken shale is in two states, only information on Bakken activity in North Dakota is summarized in Table 4.2.

Using the approach and assumptions noted above, the results reveal that from 2012 to 2014 the Bakken, Marcellus/Utica, and Niobrara shale regions had significantly more FG energy than would be required to treat the generated WW in the respective regions. In other words, the volume of FG might be considered a bigger environmental challenge than WW volumes in these regions. By contrast, Haynesville and Permian Basin had ratios much lower than one. The Eagle Ford had a ratio of approximately 0.5 in 2013 and 2014.

In Figure 4.2, the energy in the FG and primary energy required for WW treatment are shown for each region, along with the energy surplus ratio. Figure 4.3 shows the volume of generated WW and volume of TW that could have been generated had the FG energy been used for WW treatment by region. The TW recovery rate depends heavily on the WW quality, specifically the TDS concentration. As such, the recovery rate is also included in the figure. The US map in Figure 4.4 shows the energy surplus ratios, E_{FG}/E_{TW} for 2014 by shale region. This map highlights the regions that, from a technical stand point, appear to have had a surplus of energy in the FG compared to the amount of energy required to treat the WW. Table 4.2 and Figures 4.2-4.4 reveal that FG was the dominant waste stream in the Bakken, Marcellus/Utica, and Niobrara regions during the years 2012 through 2014. By contrast, WW was the dominant waste stream in shale plays in Texas including the Eagle Ford, Permian Basin, and Haynesville.

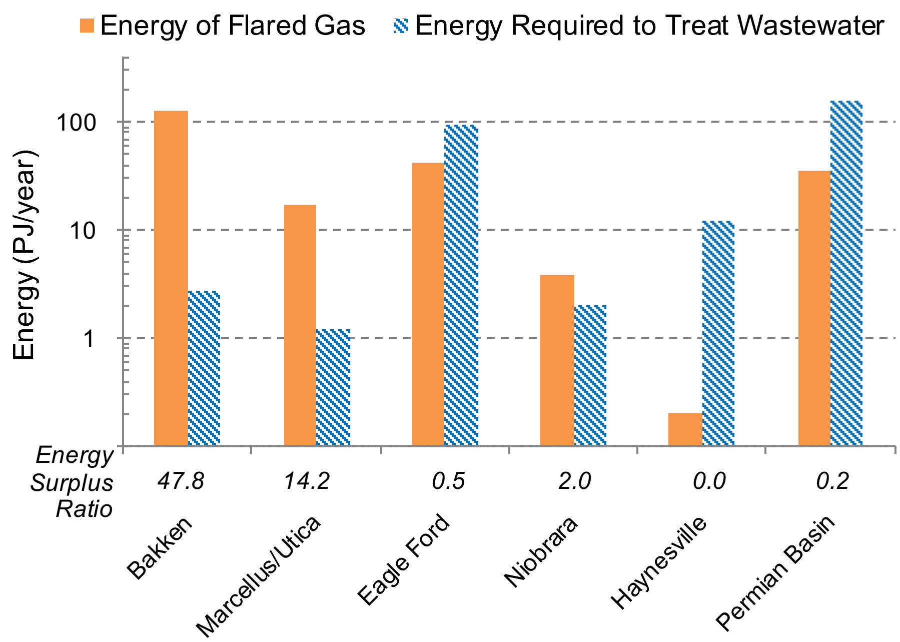

Figure 4.2: Primary energy of FG and primary energy required for WW treatment for the shale regions of interest in 2014. The data presented for Marcellus/Utica is from 2013, due to lack of data availability for 2014 at the time of this study. The energy surplus ratio, E_{FG}/E_{TW}, is also included for each of the regions.

4.6.1 Regions Where E_{FG}/E_{TW} Is Greater Than One

- **Marcellus/Utica**: A mostly gas-producing region, appears to have flared far more energy than would be needed for treatment of the generated WW. This high E_{FG}/E_{TW} ratio could be attributed to the fact that the volumes of WW were low for this region. The Marcellus/Utica region also has few SWD sites, which means WW requiring disposal must be trucked long distances, resulting in a logistical scenario that might favor onsite treatment of WW. The WW in Marcellus/Utica averages approximately 130,000 mg/ℓ TDS, low enough that

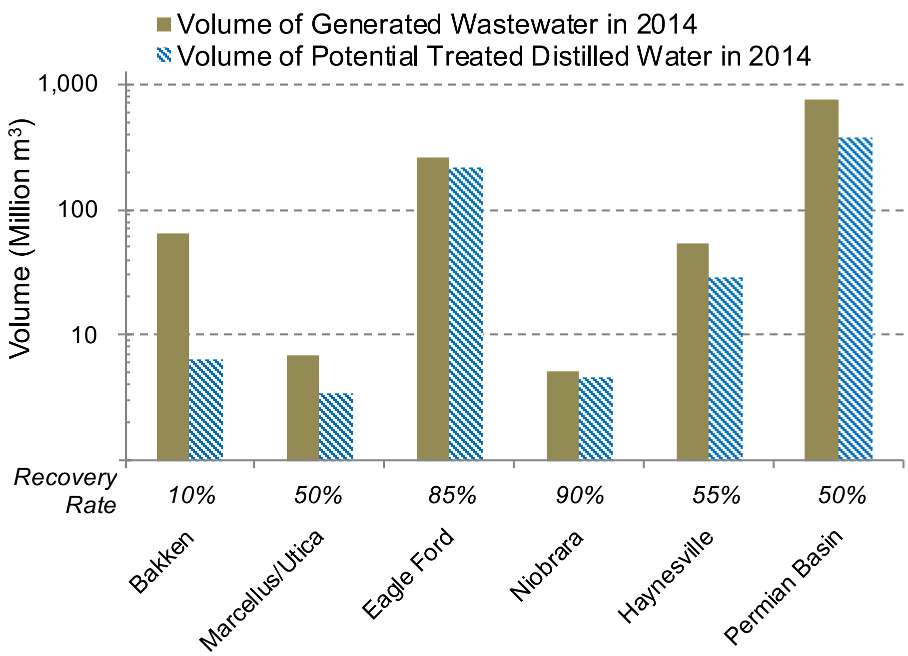

Figure 4.3: Volume of WW and the potential volume of TW that could have been generated if the FG energy had been applied to WW treatment for the shale regions in 2014. The recovery rate of MVR for each region is also included.

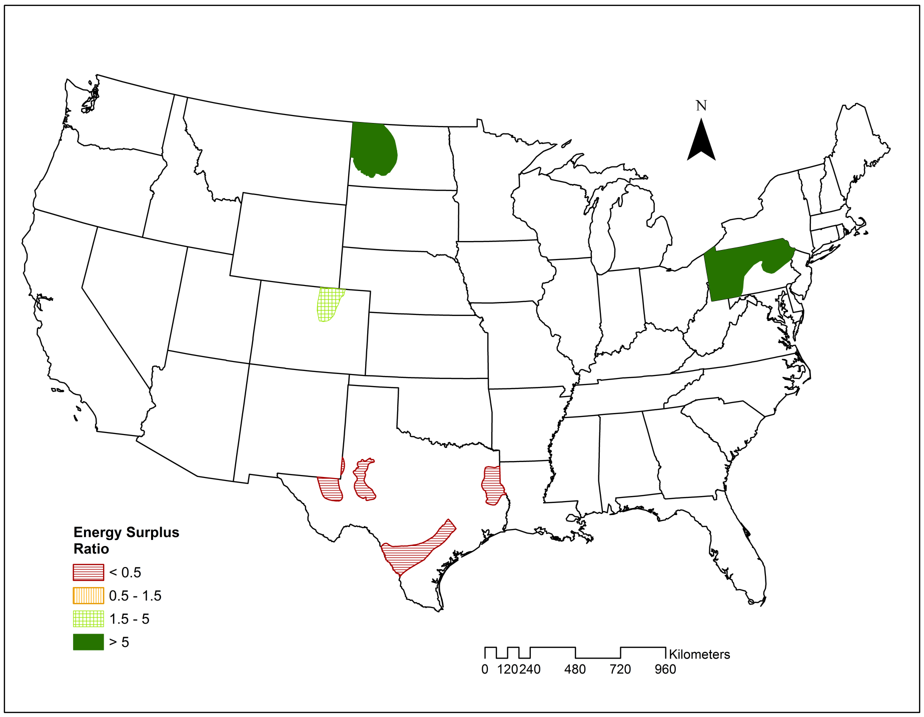

Figure 4.4: Energy surplus ratios, E_{FG}/E_{TW}, for each region in 2014. The data presented for Marcellus/Utica are from 2013, due to lack of data availability in 2014 at the time of this study.

technologies like MVR are effective in treating the water [37, 65]. In fact, some operators are already treating their WW onsite [66].

- **Bakken**: Approximately 45 times the amount of energy required for WW treatment was flared in the Bakken during 2012-2014. However, the extremely dirty WW with TDS concentrations upwards of 200,000 mg/ℓ make treatment to freshwater standards unlikely [31]. While WW treatment appears to be impractical in the Bakken due to the extremely challenging WW quality, the abundance of FG presents opportunities for other beneficial options such as replacing diesel generators with natural gas generators to supply onsite power. In 2015 and the first half of 2016, the amount of FG in the Bakken decreased significantly in comparison to the 2014 data presented herein. In fact, the fraction of total gas production that is flared in North Dakota has declined from 36% in January 2014 to 10% as of March 2016 [67]. This decline in flaring can be attributed in part to the targets for reducing flaring that were set by the North Dakota Industrial Commission. In addition, the decline in oil prices around 2015 and subsequent decline in drilling operations in North Dakota has also likely impacted FG volumes in the Bakken.

- **Niobrara**: While the FG energy was more than enough to treat the WW, aggregated volumes for both FG and WW were fairly low in the Niobrara as compared to most of the other regions considered in this study. The WW quality in the Niobrara is relatively conducive to treatment with MVR since typical WW TDS levels are approximately 25,000 mg/ℓ [18]. In fact, as mentioned in Chapter 3, this TDS level makes Niobrara WW a candidate for treatment using reverse osmosis (RO). Because RO is less energy intensive than MVR, it is a candidate for further analysis in future work.

4.6.2 Regions Where E_{FG}/E_{TW} Is Less Than One

All three regions where there is insufficient FG energy to treat all the generated WW are in Texas, an area of the US that has had significant oil and gas activity for many decades and, therefore, has built extensive gas gathering and WW disposal infrastructure. Consequently, these areas also have much greater access to non-flared energy sources (grid-tied electricity and marketed natural gas, for example) for managing wastewater.

- **Permian Basin**: Approximately 752 million m^3 (nearly 200 billion gallons) of WW was generated in the Permian Basin in 2014. This volume represented 66% of all the WW generated from the seven shale regions of interest. The Permian Basin is also arid, which means treating and reusing WW could be an important source of water for O&G operations in the region. In fact, some operators in the region are already reusing their treated WW [68]. As such, the practice of treating and reusing WW might grow because it helps mitigate challenges related to sourcing water in an arid environment. Relatively low FG volumes compared to the number of completed wells in the Permian Basin is likely due in part to the fact that the region has well established gas pipeline infrastructure that allows produced natural gas to be brought to market. Consequently, approximately 2% of the natural gas produced was flared in the region in 2014, which is much lower than in the Bakken shale [69]. To treat the WW generated in 2014, approximately 8% of the natural gas produced and sent to market in the region would have needed to be diverted to treatment. The region is also rich in renewable energy resources such as wind and solar. As such, rather than diverting natural gas, another approach could be to couple renewable resources with water treatment [45, 71–73].

- **Haynesville**: The Haynesville shale region had very low levels of FG and relatively low volumes of WW generated from 2012 through 2014. In addition, the WW is fairly poor quality in this region making treatment less attractive [29]. For these reasons, along with the fact that the Haynesville region has many SWD sites, WW treatment appears less viable compared to other regions considered in this study.

- **Eagle Ford**: While the amount of FG energy is insufficient to treat all the generated WW, the FG could have provided approximately 50% of the regionally averaged energy requirements in the Eagle Ford in 2014. Other factors that make treatment in the region appealing are the low TDS concentrations, which average 40,000 mg/ℓ, and arid conditions that often leave the area water-stressed [19, 29].

4.7 Takeaways

The focus of this objective was to evaluate volumes of generated WW and FG associated with unconventional O&G activity in seven of the major shale regions in the US. Understanding these volumes and their relative magnitudes in the various regions can help inform management and mitigation strategies for these waste streams. In addition, if the FG energy were repurposed for WW treatment, then two waste streams could be reduced and also converted into a valuable commodity of TW. Aggregated volumes of FG and WW were curated from a variety of sources, primarily state and federal agencies. The treatment technology MVR was used as a benchmark along with engineering models to assess theoretical energy requirements for WW treatment and TW recovery rates.

This work shows that the Bakken, Marcellus/Utica, and Niobrara had sufficient energy from FG (on an aggregated basis across the region) to treat the WW that was produced from O&G operations in each respective region from 2012 through 2014. The available energy from aggregated FG in the Eagle Ford, Permian Basin, and Haynesville was sufficient to meet approximately 50, 20, and 2% of the energy requirements for WW treatment in the regions in 2014, respectively, meaning that water management strategies such as treatment and reuse would require energy sources in addition to the FG.

The largest sources of FG and the region with the most WW are not aligned. The Bakken flared more than 3.3 billion m^3 (117 billion ft^3) of natural gas in 2014, approximately 57% of all the gas flared in the seven regions considered and approximately 41% of all flared and vented gas in the US in 2014 [59]. The Permian Basin on the other hand produced approximately 752 million m^3 (nearly 200 billion gallons) of WW in 2014, 66% of all WW produced in the seven shale regions considered, but flared relatively little gas.

The proposed strategy should be considered on a well-by-well basis in future studies and within the prevailing regulatory context. While the prospect of using FG for WW treatment might not be aligned across the entire shale region, it might be well-matched for individual wells or drilling pads or vice versa. Each well will have unique operating conditions such as the flow rates for FG and WW, the availability of local water resources, and the presence of pipeline and SWD infrastructure. These factors, among others, might make the proposed strategy appealing for certain wells. However, the logistical challenge of matching the temporal and spatial variations of WW and FG supply presents a challenge for implementation at many wells. As a result, the conclusions provided herein that detail which regions have sufficient aggregated FG to treat the WW serve as a first-order identification of regions where

O&G operators might consider implementing the proposed strategy.

Many critical aspects are not discussed in this analysis, including economic feasibility, logistical challenges, and impacts of regulatory changes on the overall landscape. While economic feasibility is key to understanding the potential of using FG for WW treatment, this type of economic analysis depends on first conducting a technical assessment as presented in this study. A deeper analysis of economic feasibility is beyond the scope of the current study given the deep complexity required in performing a rigorous financial assessment on a site-specific basis but is part of ongoing work where the capital and operational costs of the current practices are compared with a variety of waste stream mitigation approaches on a case-by-case basis.

It is currently unclear what a low-price oil environment would do for the prospects of WW treatment. On one hand, operators look for every opportunity to improve operational efficiency. On the other, reduced capital spending will likely limit the growth of new hardware in the field. Regions with known water scarcity or limited WW disposal sites might be more inclined to treat and reuse WW. In addition, the volume of FG in each region will likely decrease as gas pipeline infrastructure catches up with the expansion in drilling operations that occurred during 2011-2015. Lastly, changes in regulations that impact current practices for sourcing HF water, changes that expand beneficial uses of WW, or new limits on allowable volumes of FG might encourage operators to consider new alternatives for how they manage both FG and WW. Future work should provide a detailed assessment of costs, logistics, and the impacts of regulations when considering whether it is feasible to use the energy from FG to power WW treatment.

Chapter 5

Decision Tree Model for Evaluating Produced Water Management Pathways

5.1 Introduction

Depending on the shale region, there could be several important produced water (PW) management pathways to consider aside from disposal via SWD sites or minimal treatment and reuse for subsequent well completions. For example, road spreading for de-icing in the winter, use in industrial applications such as cooling, treatment to potable standards for municipal applications, or non-potable standards for irrigation, among many others.

This research objective investigates the uncertainty and financial tradeoffs of several PW management pathways by employing decision analysis methodology to aide in selecting the most appropriate option at a given site. A decision tree model was developed that incorporates capital expenditures (CAPEX), operating expenses (OPEX), potential revenue, and associated uncertainty for each pathway. The framework is demonstrated using an historic O&G producer site in Wyoming, a region that is often water-stressed and faces unique regulatory constraints.

5.2 Background

Wyoming is one of the top ten natural gas-producing states in the US, producing approximately 2-3% of U.S. crude oil [74]. In addition, between 2011 and 2014, more than half of all the hydraulically fractured wells drilled in the state were in areas with high to extremely high water stress levels [75]. Finally, while the state's regulatory context is often seen as friendly to O&G production, some of Wyoming's environmental regulations and restrictions surrounding onsite PW discharge and other PW management strategies have nontrivial implications on O&G production. This constraint is especially true in regions where O&G production is associated with high volumes of PW.

The Wyoming O&G site analyzed for this work covers over 100,000 acres, with ongoing production of primarily natural gas from about 200 wells. PW from its operations have relatively low levels of total suspended solids (TSS) and an average of approximately 10,000 mg/ℓ TDS concentration. The volumes of PW averages around 32 m^3 (8,400 gallons) of PW per day per well for a total of about 6,360 m^3 (1,680,000 gallons) per day. There is currently one water treatment facility onsite processing approximately 3,980 m^3 (1,050,000 gallons) of PW per day. Figure 5.1 shows a schematic of current operations at the site whereby the PW will either be used to complete a subsequent well, treated in the facility that is powered by onsite generators, or disposed of either in a SWD well or in an evaporation pit. The majority of the treated water is discharged while a small fraction is used to meet the water needs in the various facilities onsite.

More traditional PW management strategies at the site (i.e., discharging to a nearby stream or disposal via SWD well) are challenging for two reasons. First, state regulations currently cap the volume of PW that can be discharged on the property to a specific monthly maximum tonnage of salt. Second, few onsite SWD wells are currently available. Drilling additional SWD wells is an expensive option due to geologic constraints. O&G production levels at the site are constrained as a result of these two limitations in traditional PW management strategies.

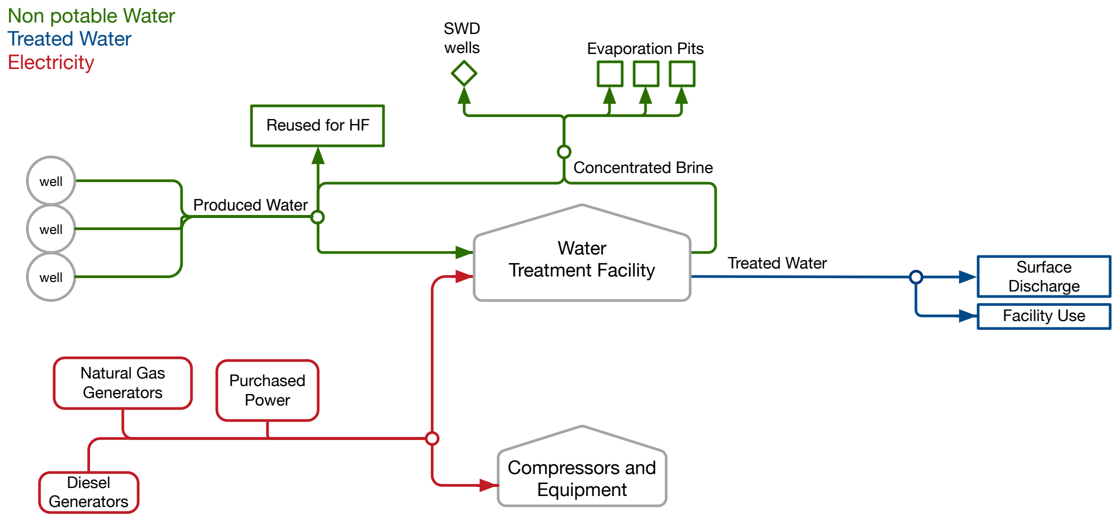

Figure 5.1: This schematic shows current operations at the Wyoming O&G site investigated in this study.

To meet future O&G production goals, up to approximately 110,000 m^3 of PW per day (29.4 million gallons) would need to be managed for 25 years of expected O&G production. Without a method of handling a significant increase in PW volume, the operator cannot expand O&G production. Given the current constraints in employing traditional PW management strategies, nontraditional management pathways might provide an economical solution to increase O&G production.

5.2.1 Background on the Investigated Nontraditional Produced Water Management Strategies

The three nontraditional PW management strategies investigated in this study were chosen because of their potential to repurpose the PW for beneficial uses and generate revenue in the process.

1. *Pipe to municipality:* Growing demand from urban areas for secure and stable water supplies was the impetus to include treating and selling PW to munici-

palities [76]. In addition, municipalities are often willing to pay higher prices for the water than agricultural and industrial customers [77].

2. *Irrigate terrestrial energy crop onsite:* Crops such as switchgrass can be irrigated with non-potable water and used as a biomass alternative to existing fuel demand for coal-fired power plants [78]. Offsetting the demand for coal by growing energy crops can provide environmental benefits, such as reducing lifecycle emissions from legacy power plants [78].

3. *Grow greenhouse crops onsite:* Onsite greenhouses offer a temperature- and humidity-controlled environment for growing high-value crops. These characteristics allow regions with long periods of cold weather, like Wyoming, to potentially irrigate crops that would otherwise be impossible to grow due to harsh climate conditions.

While this study was limited to the three options above due to their perceived likelihood of success and economic feasibility, several other nontraditional PW management pathways were considered including:

- Sending treated water to a nearby industrial plant or power plant.
- Building an industrial plant onsite (e.g., chemical plant producing hydrogen or ammonia) that uses the treated water.
- Recovering minerals such as salts from the concentrated brine for use in road de-icing.
- Raising livestock onsite.

These additional nontraditional PW management options were investigated but not included in this work because an initial assessment deemed them unlikely to be financially viable or otherwise sufficient to facilitate an increase in hydrocarbon production onsite. It should also be noted that while nontraditional applications for beneficial reuse of treated PW were explored, precedent exists for both irrigating crops and supplying municipalities with treated PW [79, 80]. Figure 5.2 shows a schematic of potential options for nontraditional beneficial reuse of treated PW.

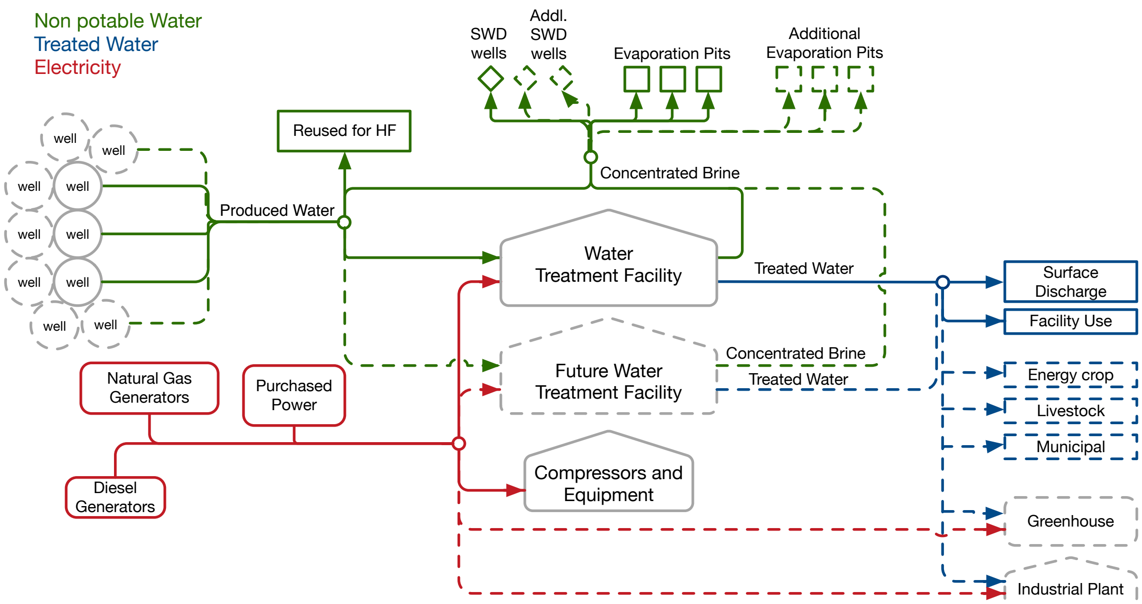

Figure 5.2: In this schematic, possible nontraditional options for PW management pathways (dotted lines) are overlaid on top of current operations (solid lines). Nontraditional options could allow an increase in O&G production at the site by managing the increase in PW that returns to the surface with it.

5.2.2 Traditional Produced Water Management Strategy Investigated

One traditional PW management pathway, treating the PW to 5,000 mg/ℓ TDS concentration (i.e., approximately half of the starting concentration) and discharging to a nearby stream, is also explored in this study and compared to the nontraditional options.

5.3 Methodology

A decision tree model, a tool within decision analysis that facilitates systematically calculating each option's expected value[1], was built to aid the decision-making process among the four PW management pathways. The general expression for the expected value of a discrete random variable is shown in Equation 5.1 where *p(x)* is the probability mass function of the discrete random variable, X.

$$E[X] = \sum_{x:p(x)>0} xp(x) \tag{5.1}$$

Since the decision tree is too large to show in its entirety in one image, it is displayed in Figures 5.3-5.5. Figure 5.3 shows the first part of the decision tree including the four pathways under consideration and their associated decision and uncertainty nodes depicted by squares and circles, respectively. Triangles in the decision tree signify the end of the branch. Figures 5.4 and 5.5, are continuations of the decision tree as noted in Figure 5.3.

5.3.1 Financial Model and Calculating Present Value

Since the goal of this objective is to determine the expected value of each PW management pathway over the production duration, a financial model was built to calculate the present value[2] of each branch of the decision tree. Once the present value was calculated for each branch, it could be used to determine the expected

[1]For a discrete random variable X, the expected value is "a weighted average of the possible values that X can take on, each being weighted by the probability that X assumes that value." [81]

[2]Present value is the current worth of a future sum of money or stream of cash flows given a specified rate of return [82].

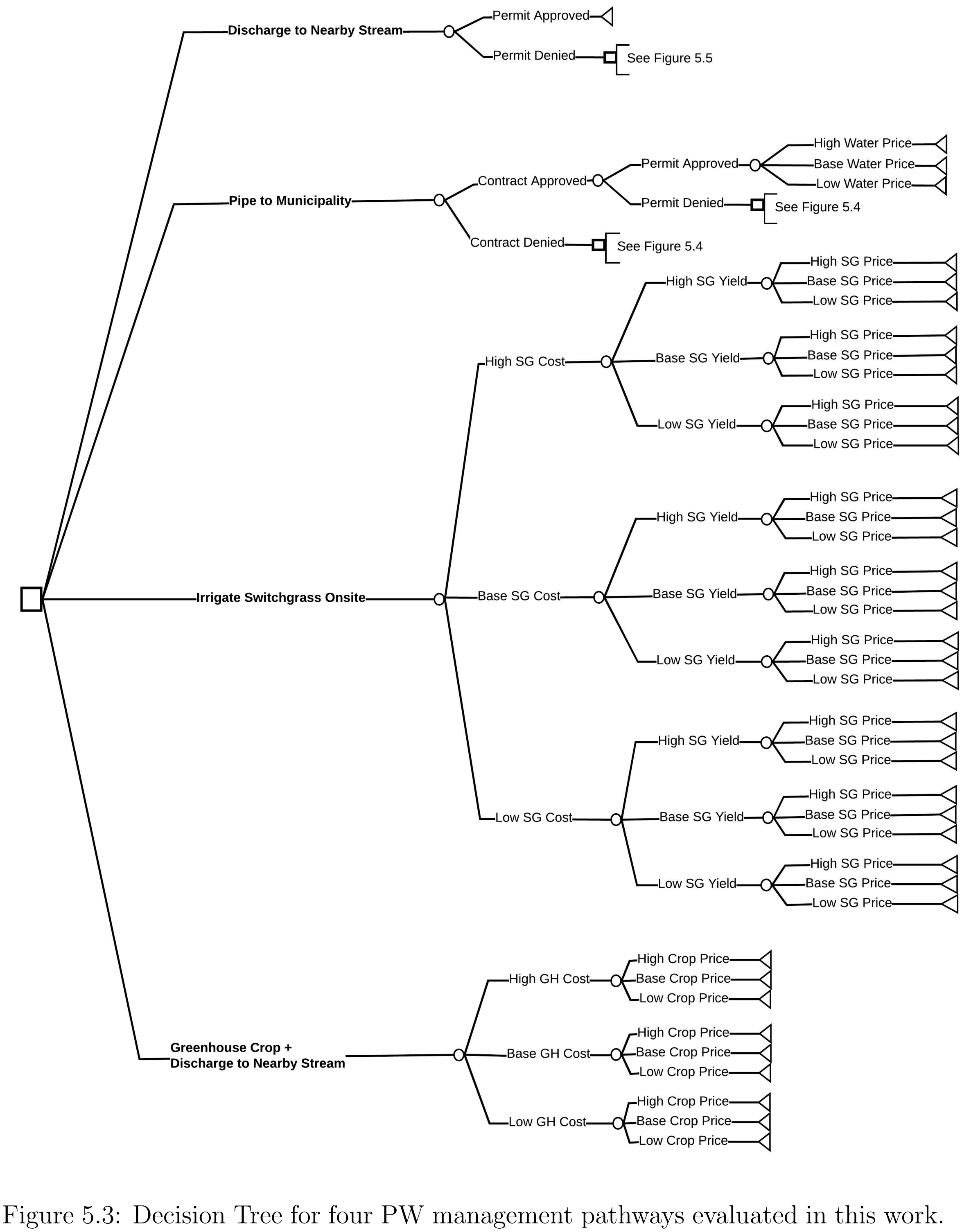

Figure 5.3: Decision Tree for four PW management pathways evaluated in this work.

value of each option by multiplying by the probability of that option occurring. The financial model assumes a 25-year production period with 5.5% annual discount rate and includes CAPEX, OPEX, and revenue streams. The production start depends on the expected time to obtain required permits/contracts and installing necessary capital and, as described in more detail in Section 5.3.2, is uncertain.

As an example, Table 5.1 shows a snapshot of the first seven years of a financial assessment to determine the present value of growing switchgrass assuming a base cost and base price. The financial model allows for revenue streams for both O&G and crop sales. The costs include the CAPEX and OPEX associated with water treatment, water disposal, and growing switchgrass. A similar financial assessment was made for each case represented in the decision tree. That is, for the option to grow switchgrass, there are 27 cases represented in the decision tree, each of which has its own financial assessment similar to the one shown in Table 5.1.

Table 5.1: This table serves as an example of the financial assessment performed for each case of the decision tree. Only the first seven years are shown in this example whereas the actual financial assessments all have a 25-year production period.

Time		Year	0	1	2	3	4	5	6	7
Revenue										
	Natural Gas Sales	$ Thousands	–	–	–	0	0	0	0	0
	Switchgrass Sales	$ Thousands	–	–	–	8,070	8,070	8,070	8,070	8,070
Total Revenue		$ Thousands	0	0	0	8,070	8,070	8,070	8,070	8,070
Cost										
	Water Treatment									
	CAPEX	$ Thousands	91,200	0	0	0	0	0	0	0
	OPEX	$ Thousands	–	–	–	13,800	13,800	13,800	13,800	13,800
	Water Disposal									
	CAPEX	$ Thousands	243,000	0	0	0	0	0	0	0
	OPEX	$ Thousands	–	–	–	1,800	1,800	1,800	1,800	1,800
	Switchgrass									
	CAPEX	$ Thousands	88,400	0	0	0	0	0	0	0
	OPEX	$ Thousands	–	–	–	7,500	7,500	7,500	7,500	7,500
Total Cost		$ Thousands	422,600	0	0	23,100	23,100	23,100	23,100	23,100
Discount Factor		%	100	94.79	89.85	85.16	80.72	76.51	72.52	68.74
Cash Flow		$ Thousands	(422,600)	0	0	(15,000)	(15,000)	(15,000)	(15,000)	(15,000)
Discount Cash Flow		$ Thousands	(422,600)	0	0	(12,800)	(12,100)	(11,500)	(11,000)	(10,300)
Present Value		$ Thousands	(603,000)							

5.3.2 Decision Tree Uncertainty and Inputs

Uncertainty is associated with each management pathway shown in the decision tree in Figure 5.3. Three main types of uncertainty are represented in the model, including 1) the ability to obtain the required approvals, 2) the likely associated cost, yield, and product prices, and 3) the time to implement the strategy. The first type of uncertainty applies to management strategies that require permit and/or contract approvals to proceed such as discharge to a nearby stream or pipe to a municipality. Failure to acquire the proper approvals means the option cannot be pursued further. The second type of uncertainty pertains to the likely associated costs, crop yields, and/or product prices that are realized for each option. Lastly, there is inherent uncertainty in the time it could take to obtain permit/contract approvals and build out the necessary capital for each pathway. The duration for O&G production is assumed to remain 25 years regardless of how long it takes to obtain permits/contracts and install capital.

While the decision tree model was built to accommodate varying input values and their probabilities, in many cases, limited data are available to suggest appropriate ranges and their respective probabilities. For example, data are sparse on the price range and probabilities the municipality would be willing to pay for treated water. As such, the baseline value at each uncertainty node was defined by an average value for cost, crop yield, and product price. The product price required for each pathway to be profitable was also calculated. In addition, a sensitivity analysis to see which inputs most heavily impact the outputs of the model was performed. Table 5.3 lists the average values for each variable as well as their expected minimum and maximum values based on currently available data. The model allows inputs to be updated or modified as more information is obtained or conditions change. Appendix F contains information on data used to calculate values listed in Table 5.3.

5.3.3 Water Treatment Requirements

Two distinct water quality levels are required for the four pathways. Based on known crop growth performance and state regulations, the options to irrigate an energy crop and discharge to a nearby stream (pending permit approval) would require water quality with a maximum of 5,000 mg/ℓ TDS concentration [83]. For piping to a municipality and for many greenhouse crops, the PW would need to be of freshwater quality standard (approximately 200-500 mg/ℓ TDS concentration). Water treatment costs for both levels of water quality were estimated using the Unified Costing Model developed for the Texas Water Development Board and summarized in Table 5.2 [84]. A recovery rate of 87% is expected from an RO system based on both the average PW TDS concentration and known RO system efficiencies [85]. This recovery rate means 13% of the influent stream becomes a concentrated brine that is assumed to require disposal. Since the O&G site currently has very few disposal wells, the associated CAPEX and OPEX for both water treatment and brine disposal are included in the costs for each PW management strategy. The CAPEX and OPEX for SWD wells was obtained from the operator. The main difference assumed in this study between treating the water to 5,000 mg/ℓ TDS concentration or freshwater is the treatment facility size. That is, treating to 5,000 mg/ℓ is assumed to be a result of treating a little over half of the PW to freshwater and blending back with PW that has received little to no treatment. Treating to 5,000 mg/ℓ would also mean there is less brine requiring disposal. Table 5.2 shows the associated CAPEX and OPEX for both water treatment and brine disposal for the two treatment levels.

Table 5.2: Associated CAPEX and OPEX for water treatment and disposal for the two levels of water quality calculated using the Unified Costing Model developed for the Texas Water Development Board [84].

	5,000 mg/ℓ TDS concentration	Freshwater
Treatment CAPEX ($ million)	91.2	154
Treatment OPEX ($ million/year)	14	23.4
Disposal CAPEX ($ million)	243	455
Disposal OPEX ($/barrel)	0.1	0.1

5.3.4 Pipe to Municipality

The O&G site is relatively far from large cities with Denver being the closest major metropolis at approximately 300 miles from the site. Colorado's population is expected to nearly double by 2050, with the majority of the increase occurring in the greater Denver area [86]. In addition, water demands are estimated to increase in the area anywhere from 62% to 103% due to both population growth and climate change [87]. The rise in water demand means water planning experts are likely to explore a variety of options and opportunities that will secure additional water resources including purchasing treated PW. In fact, treated PW is already being used for municipal purposes in Colorado [80]. As such, the greater Denver area was chosen as the potential municipal customer in this analysis.

As the decision tree in Figure 5.3 shows, there are several uncertainties associated with the option to pipe to a municipality including 1) getting a contract approved, 2) obtaining the required permits to build the pipeline and associated capital, and 3) the price a municipality is willing to pay for the water. In addition, there is uncertainty around how long it could take to obtain the permit/contract approvals and install the capital.

Determining the likelihood of contract and permit approval is challenging since water pipeline projects of this magnitude are often planned based on a unique set of circumstances and requirements. The unique nature of different water projects, including the political support at the time of planning, financing, design, and construction, makes it difficult to determine representative conditions to use in a model. In the absence of more detailed information, the probability of permit and contract approval is assumed to be 50%. This probability can be modified in the model as more information becomes available. It is assumed that this project would likely be financed either by the O&G operator or private investment (in collaboration with the municipality that agrees to purchase the water). The time to approval and project completion is also highly uncertain with current water pipeline projects of relatively comparable size and complexity expected to take almost a decade or longer from initial design to completion. That said, water pipeline projects can experience significant timeline delays due to litigation, lack of finance, or other reasons.

Limited data on water purchase prices for Denver are available to support what prices the O&G operator might expect to receive. In this model, the mean water price from publicly available water transfer prices in Colorado between 1987 and 2008 (adjusted for inflation) was used and is listed in Table 5.3 [88]. Appendix F has additional details on how the average water price was determined. Capital requirements for the pipeline were estimated based on ongoing and historical water projects of similar size.

In the event either the permit or contract are denied for this approach, the operator will have the option to choose one of the three remaining pathways for PW management as shown in Figure 5.4. The resulting penalty for changing course from piping to municipality to another option is primarily lost time and thus potential lost revenue due to delay in ability to increase O&G production which is accounted for in the model.

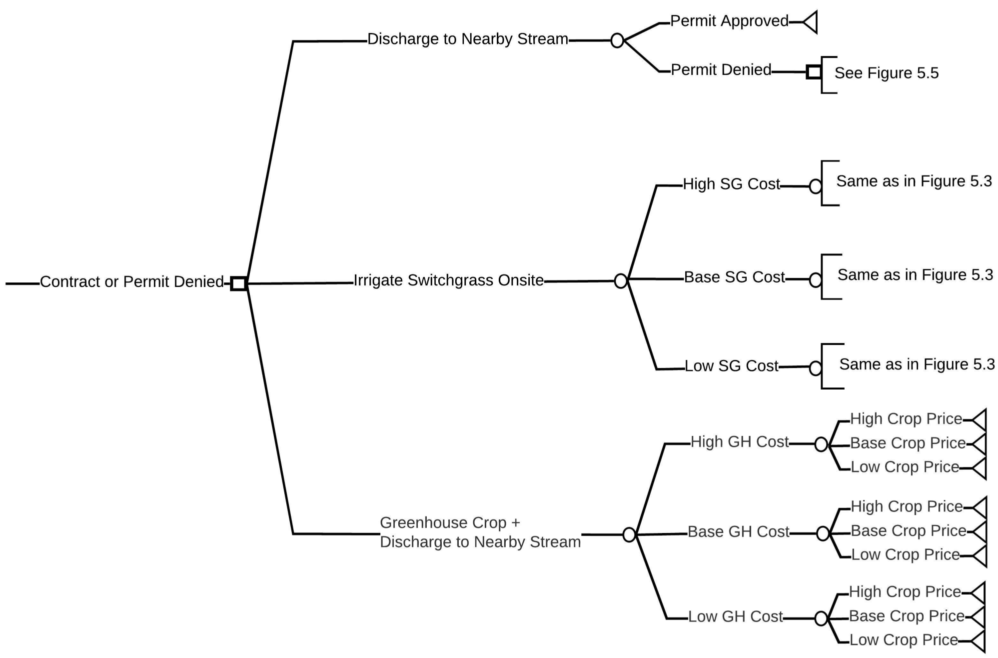

Figure 5.4: Continuation of decision tree from Figure 5.3 in the event that a contract or permit is denied for piping to municipality option.

5.3.5 Irrigating Energy Crops Onsite

Switchgrass was chosen as the energy crop for this analysis for several reasons including its high yields despite low fertilizer requirements, tolerance to high salinity water, successful growth in neighboring states, and resistance to pests and plant diseases [8, 83, 89]. In addition, switchgrass can be co-fired with coal to produce electricity or converted to ethanol to serve as a transportation fuel.

The decision tree in Figure 5.3 shows the uncertainty related to growing switchgrass including farming costs, crop yield, and price for switchgrass. Some data on costs and crop yield for switchgrass farming are available for nearby states from published studies and the averages are listed in Table 5.3. Appendix F contains additional information on the data used to determine average cost and crop yield for switchgrass. The price range attainable remains highly uncertain for switchgrass since there is no current market for it as an energy fuel. Values between $50 and $66.50 per metric ton were suggested as potential market prices [90, 91].

Switchgrass requires a minimum of 20 inches of water per year for optimal growth [91]. This region of Wyoming receives approximately 13 inches of rainfall per year which means the treated water could serve as the additional seven inches of water required to grow the crop [92]. Given switchgrass's water requirements and the expected volume of treated water to manage, the land required to grow the energy crop was calculated to be approximately 50,000 acres, less than half of the O&G site.

5.3.6 Irrigating Greenhouse Crops Onsite

Growing high value crops in greenhouses year-round in Wyoming will require access to a supply of high-quality water and abundant energy for heat. The O&G site offers a few opportunities that might make greenhouses appealing including: 1) PW can be treated to provide an abundant supply of freshwater, 2) access to natural gas can serve as a less expensive alternative to heating with propane, 3) trucks have easy access to the site, and 4) there is ample space to achieve economies of scale. Many possible high-value crops can be grown in greenhouses. Determining the preferred crop to grow can be challenging and depends on a variety of factors including regional and national market demand and local farming expertise, among others [93, 94]. For this study, a single crop, red bell peppers, was chosen to illustrate this option. Growing red bell peppers in greenhouses was selected because they sell at higher prices on average compared to typical produce and their yield and quality are often higher in greenhouses compared to their field-grown counterparts [95]. It was assumed that the greenhouses would sit on 72 acres of land as this is the average operation size of greenhouses in the US [96]. The model assumes the remaining treated PW would be piped to a nearby stream and discharged; however, additional beneficial uses for it could be considered in the future.

Two main uncertainties associated with onsite greenhouses are shown in Figure 5.3, including the cost to build and operate the greenhouses and the realized price for the produce. The controlled environment of a greenhouse greatly reduces the crop yield variability. As such, a constant red pepper crop annual yield of approximately 2 pounds per square foot was assumed [97]. Greenhouse costs can vary due to local prices for construction material and labor as well as costs for heating and other consumables such as fertilizer. The price for the produce can vary depending on market demand. For this study, historical red bell pepper wholesale prices for one day each month between 2014 and 2016 were pulled from the U.S. Department of Agricultures Fruit and Vegetable Market News Portal for the San Francisco terminal market [98]. Inputs used for both the greenhouse cost and prices for red bell peppers are listed in Table 5.3.

Table 5.3: Inputs for the variables in the decision tree model.

Description	Minimum	Average	Maximum	Source
Probability of permit approval to discharge to nearby stream at 5,000 mg/ℓ TDS concentration	0	0.5	1	
Probability of permit approval to pipe to municipality	0	0.5	1	
Probability of contract approval to pipe to municipality	0	0.5	1	
Water price obtained for piping to municipality ($/bbl)	.05	0.11	0.4	[88]
Switchgrass OPEX ($/hectare-year)	246	377	453	[8]
Switchgrass annual yield (Mg/hectare)	2	7	12	[8]
Price for switchgrass ($/Mg)	20	60.5	150	[90, 91]
Greenhouse OPEX($/acre)	80,000	113,000	147,000	[99]
Red bellpepper price ($/lb)	0.4	1.7	4	[98]
Duration to obtain permits/contracts & install capital (years)	**Minimum**	**Average**	**Maximum**	
Discharge to stream	1	3	5	
Pipe to municipality	4	8	15	
Onsite switchgrass	1	2	5	
Onsite greenhouses	1	2	5	

5.3.7 Discharge to Stream

The traditional PW management pathway analyzed in this study is discharging PW treated to 5,000 mg/ℓ to a nearby stream. The main uncertainty with this option involves obtaining the permit from the state of Wyoming. In the event the permit is denied, the operator will need to decide among the remaining branches of the decision tree as shown in Figure 5.5. Without more information, the probability for obtaining the permit is set to 50% although this value can be modified in the model as new information becomes available. It is assumed that there would be minimal difficulty to obtain a permit to discharge PW treated to freshwater standards to the nearby stream and thus include that as an additional option available to the operator in the event that a permit to discharge at 5,000 mg/ℓ is denied. Along with treatment and disposal costs, a roughly 11-mile pipeline will be required to transport the water from the property to the stream. The CAPEX and OPEX associated with the pipeline are included in the cost of this option.

5.3.8 Including Profits from Hydrocarbon Sales

Implementing one of the PW management pathways would allow for the expansion of natural gas production and sales. As such, the model gives the user the option to include expected profits from natural gas sales for each year in the 25-year operating length. Including profits from natural gas sales is intended to serve as a proxy for the company's profit margin. Since each water management pathway could have different production start times (due to the time variability to obtain permits/contracts and/or build out capital for each pathway), including the expected profits from natural gas sales gives a more holistic look at the expected values for the pathways. If natural gas profits are included, then a positive profit should be expected to justify the implementation of a water management strategy.

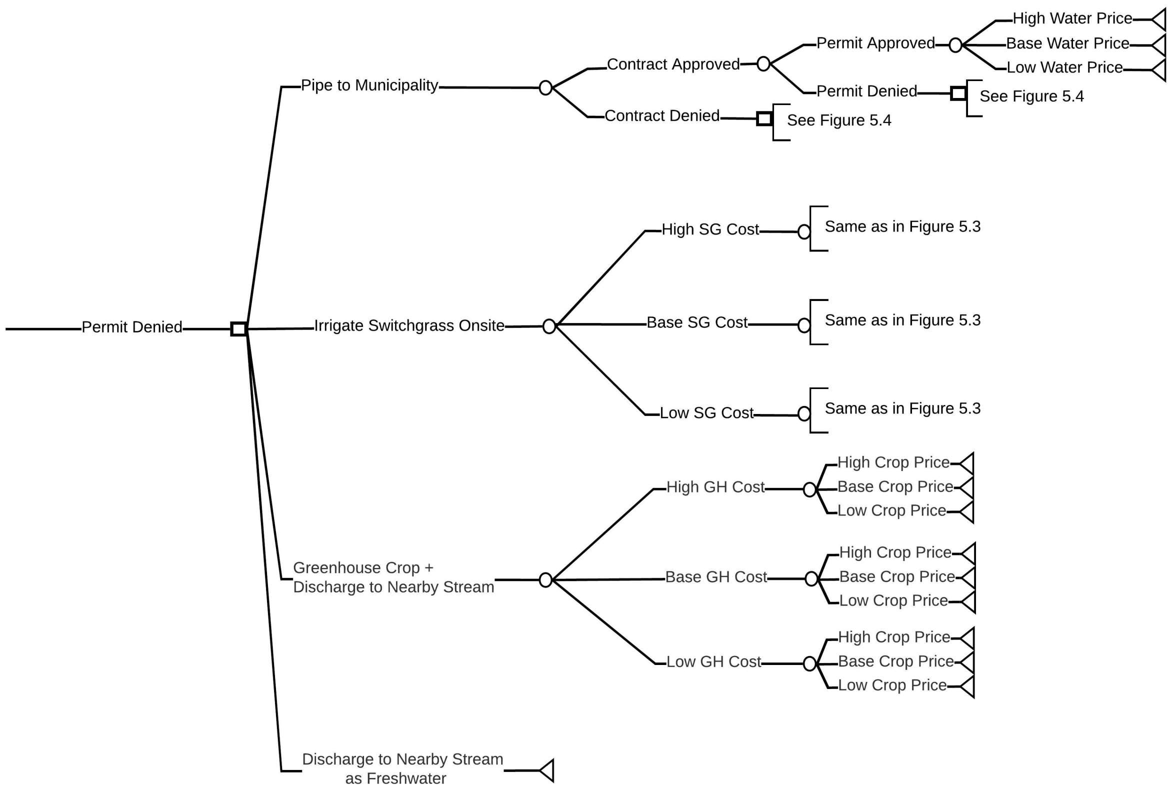

Figure 5.5: Continuation of decision tree from Figure 5.3 in the event that a permit is denied for discharging to a nearby stream at 5,000 mg/ℓ TDS concentration.

The decision tree model uses Henry Hub natural gas price futures for 2018 through 2022 since they are readily available [100]. The NG sale price was then held constant at the 2022 price for the remainder of the 25 year production period. While there is no expectation that the price will remain constant after 2022, attempting to predict or project future prices beyond a five-year horizon would be highly uncertain and beyond the scope of this work.

A value of 6% of natural gas prices was chosen to be the average profit from natural gas sales since 6.1% is the average net profit margin for the O&G industry as of January 2015 [101]. While 6% was used as a constant value, an O&G company's actual profit margin can vary dramatically from quarter to quarter depending on many variables including realized natural gas prices, cost to extract the natural gas, and changes in supply and demand of natural gas [102]. Despite the wide variability that might be expected, 6% profit on average is likely a reasonable assumption for this industry and is used to illustrate the model, not make predictions.

5.4 Results and Discussion

5.4.1 Results

The expected values of each PW management pathway were calculated using the average value for each variable listed in Table 5.3 and the CAPEX and OPEX for water treatment and brine disposal listed in Table 5.2. All four PW management options would result in negative expected values (i.e., would be cost centers) for the O&G operator based on these inputs and excluding natural gas profits. The PW management pathways ranked from highest expected value to lowest as follows: discharge to nearby stream, onsite irrigation of switchgrass, onsite irrigation of greenhouse bellpeppers, and piping to a municipality.

While each pathway's expected value is dramatically different in the scenario where natural gas profit is included, the overall rankings remain the same. That is, discharging to a stream still has the highest expected value followed by growing switchgrass, growing greenhouse crops, and piping to a municipality when natural gas profits are considered in the expected values. In both scenarios, piping to a municipality has a negative expected value (unless a third party pays the CAPEX). Table 5.4 shows the expected values calculated for the minimum, average/base, and maximum variable inputs including and excluding natural gas profits.

The two management pathways with highest expected values are the options with less stringent treatment requirements. This result makes intuitive sense since less water treatment and brine disposal would be required for these options, reducing their overall cost compared to the options requiring freshwater.

Where the average expected value is negative, the break-even price is calculated for that variable, if possible, and listed in Table 5.4. In all cases, the break-even prices are significantly higher than the average variable inputs used in the model. These high break-even price points are likely heavily influenced by the high capital costs associated with PW treatment and brine disposal. In addition, the lowest average percent natural gas profit needed to break-even on discharging to a stream (the PW management pathway with the highest expected value) was determined to be 3.4%. That is, if natural gas profits on average dip below 3.4%, increasing production by discharging to a nearby stream is a losing proposition.

While one goal is to generate a profit through one of these PW management pathways, it is not surprising that the expected values are negative for all options (when natural gas profits are excluded), as PW management is currently a cost center for O&G companies and water treatment and brine disposal are generally expensive endeavors that heavily influenced the expected values. The operator might accept incurring these expenses to handle the PW in order to dramatically increase their natural gas production and sales. Finding a way to beneficially reuse the treated PW could also have positive impacts on the operator's public image.

Based on the inputs into the model, the *Contract Approved* branch of Pipe to Municipality PW management option had a much lower expected value than the *Contract Denied* branch. This outcome means given current conditions, it does not make sense to pursue the option to pipe the treated PW to a municipality since not pursuing it is far more cost-effective. This result is due in large part to the high capital costs associated with transporting the water such a long distance coupled with relatively low water prices. As a result, the expected value calculated for the Pipe to Municipality option shown in Table 5.4 does not take into consideration the branches where a contract or permit is denied (i.e., the probability for contract and permit approval is assumed to be 100%). Similarly, probability for contract and permit approval for Pipe to a Municipality is assumed to be 100% in the event that a permit to discharge to a stream is denied and the user is deciding among the remaining options (see Figure 5.5). In addition, the expected cost for Pipe to Municipality was also calculated assuming the capital costs are paid by a third party (e.g., the government).

The net difference between the minimum and maximum expected values for each variable is roughly the same regardless of whether natural gas profits are included or not for most cases as shown in Figure 5.6. The notable exceptions are the variables involving the time to obtain permits/contracts and install necessary capital. In all of these cases, the expected value range is much greater when including the natural gas profits compared to when natural gas profits are not included. This outcome illustrates the cost associated with time lost or gained with respect to natural gas profits. Not surprisingly, the longer it takes to obtain approvals and install capital, results in lost profits from natural gas sales.

Based on the values shown in Table 5.4 and Figure 5.6, the minimum and maximum water price a municipality might be willing to pay causes the largest change in expected value compared to the minimum and maximum values of any other input variable. This result holds true regardless if natural gas profit is included and if the capital is paid by a third party. However, despite this large range, it is important to note that the expected values associated with water price are negative unless the capital is paid by a third party. If a third party pays for the capital and if the high end of water prices can be attained, piping to a municipality becomes a viable and even an attractive option. As such, determining the water price early on would help in the decision-making process.

5.4.2 Sensitivity Analysis

While Figure 5.6 shows the absolute difference in expected values between the minimum and maximum input values, the tornado diagrams in Figures 5.7–5.9 show the sensitivity to each variable on a percent change from the average/base value using the minimum and maximum expected values from Table 5.4. Figures 5.7 and 5.8 show the sensitivity to each variable on a percent basis including and excluding natural gas profits, respectively. Figure 5.9 combines the information from Figures 5.7 and 5.8 in order to more easily visualize the impact natural gas profits have on the outcomes.

Several observations can be made based on this sensitivity analysis including:

- When the capital is paid by a third party, water price is in the top three inputs that influence the expected values when natural gas profits are included and

Table 5.4: Summary of management pathway expected values ($ million) including and excluding profits from natural gas sales (assumed at 6% of natural gas prices). Break-even results are based on average value inputs as listed in Table 5.3.

	No Natural Gas Profit Included				Natural Gas Profit Included			
Description	Min	Average	Max	Breakeven	Min	Average	Max	Breakeven
Permit for stream discharge	-605	-570	-535	–	405	440	475	–
Municipal water price	-1800	-1700	-1090	0.93 $/bbl	-1030	-910	-315	0.55 $/bbl
Municipal water price (capital paid by 3rd party)	-750	-630	-33	0.42 $/bbl	22	145	740	–
Switchgrass OPEX	-620	-600	-570	–	390	405	440	–
Switchgrass yield	-670	-600	-530	50 Mg/ha	340	405	475	–
Price for switchgrass	-670	-600	-450	420 $/Mg	340	405	560	–
Greenhouse OPEX	-1020	-990	-960	–	-10	20	50	–
Red bellpepper price	-1090	-990	-815	14.80 $/lb	-80	20	190	–
Duration to obtain permits/contracts and install necessary capital (years)	Min	Average	Max		Min	Average	Max	
Discharge to stream	-580	-570	-560		400	440	490	
Pipe to municipality	-1700	-1700	-1650		-1150	-910	-790	
Onsite switchgrass	-625	-600	-585		320	405	500	
Onsite greenhouses	-1000	-990	-950		-86	20	58	

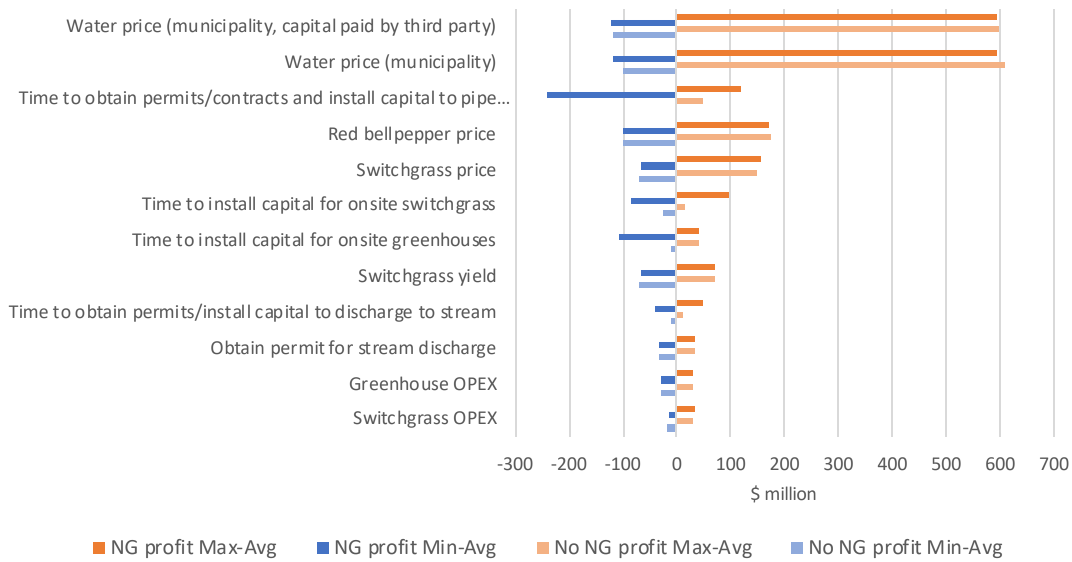

Figure 5.6: This tornado diagram shows the difference between maximum and minimum expected values based on the various inputs into the model both including and excluding natural gas profits.

excluded. Aside from water price, the remaining variables in the top three spots differ depending if natural gas profits are included or excluded. Bell pepper price and time to install capital for greenhouses are the top two variables when natural gas profits are included and water price (capital not paid by third party) and switchgrass price are the second and third variables when natural gas profits are not included.

- While time to obtain approvals and install capital seem to have the biggest impact on the expected values on an absolute basis when natural gas profits are included, they are not as impactful on a relative change from average value.

The purpose of a sensitivity analysis is to reveal which input variables have the greatest impact on the expected values. Combining these results with the expected values can help an operator understand how best to focus their efforts especially when

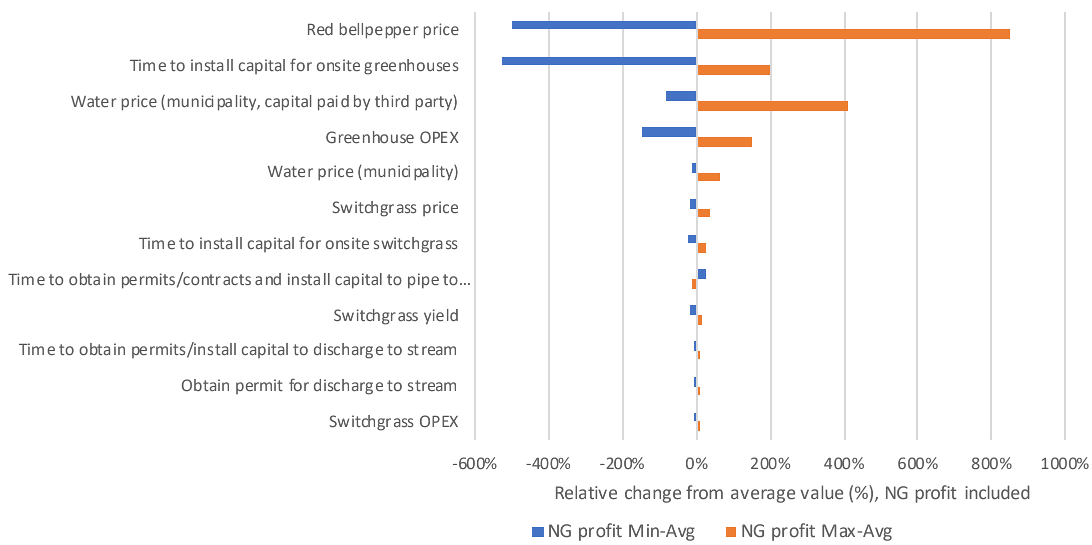

Figure 5.7: Relative change of the expected values from base values for the input variables when natural gas profits are included. Price of red bellpeppers, time to install capital for onsite greenhouses, and water price (when a third party pays the capital) are the top three most sensitive variables in this case.

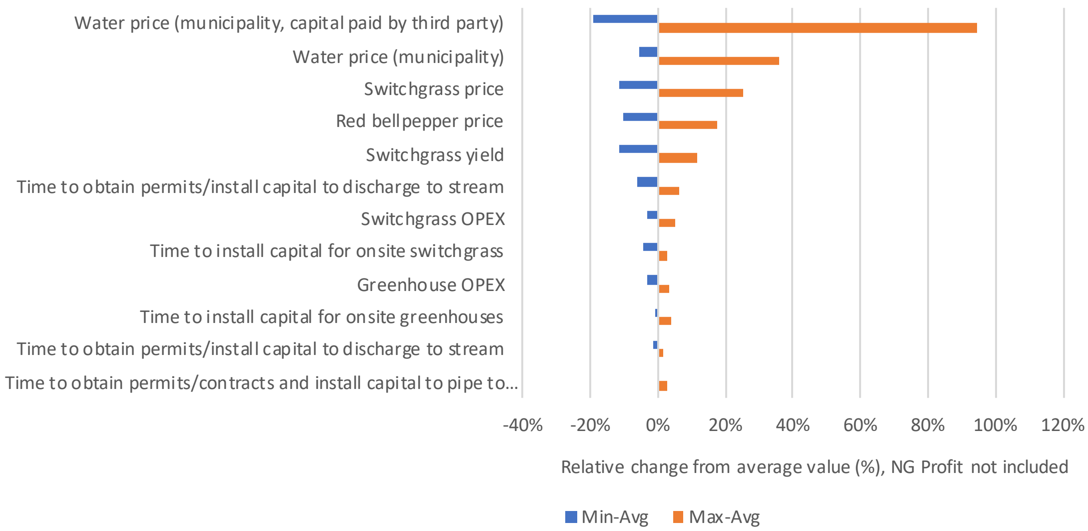

Figure 5.8: Relative change of the expected values from base values for the input variables when natural gas profits are excluded. Water price and switchgrass price are the most sensitive variables in this case.

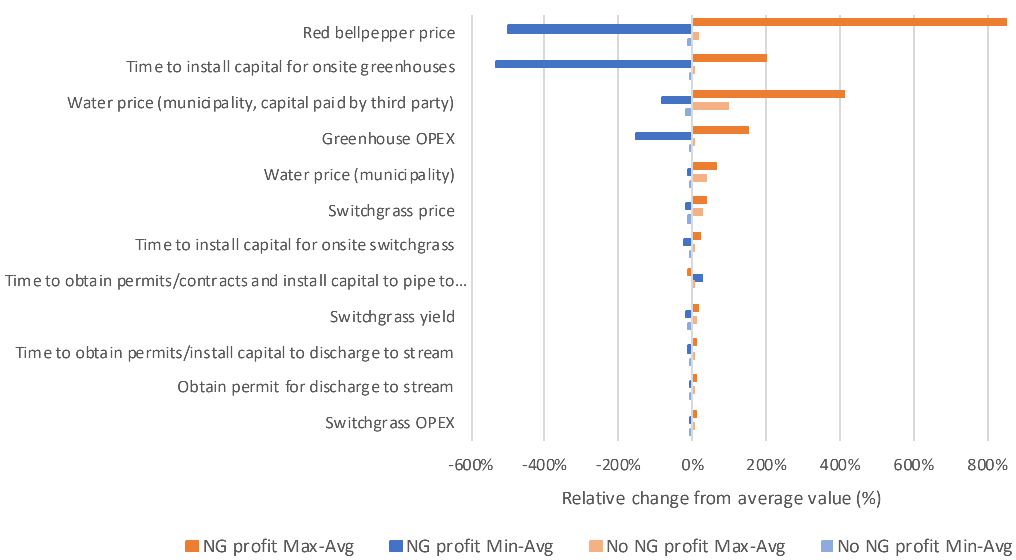

Figure 5.9: A combination of Figures 5.7 and 5.8. Note that the relative change from base value is generally much greater when natural gas profits are included.

the expected values of several PW management pathways are fairly close. As listed in Table 5.4, the expected values for discharging to a stream and irrigating switchgrass when natural gas profits are included are $440 million and $405 million, respectively. If the decision was based solely on these expected values, the decision should be to discharge to a stream. However, switchgrass has several attributes that potentially make it equally or more profitable than discharging to stream. An operator might want to investigate in more detail the likelihood they can expect to receive closer to the maximum price for switchgrass thereby making it a more attractive option compared to discharging to a stream.

Similarly, if natural gas profits are excluded, both switchgrass and piping to a municipality (when capital is paid by a third party) have expected values that are approximately 5% and 10.5% lower than discharging to a stream. These expected values are close enough that it might warrant a deeper investigation into if the operator can secure a water price close to the maximum value listed in Table 5.3. If the water price is close to the maximum value, piping to a municipality becomes far more cost effective than discharging to a stream. The operator might consider discussions with the municipality to determine the likely water price and whether the capital required to pump and transport the water could be paid by a third party.

5.5 Additional Considerations

This analysis reveals the high cost associated with the various PW management pathways explored in this work. These results help clarify why operators rarely implement nontraditional PW management options at O&G sites despite a growing desire to beneficially use PW. The following are thoughts as to why costs are so high for these options and possible strategies to lower them.

- This analysis determined that higher water prices could make piping to a municipality a viable option. That said, municipal water prices do not often reflect the real value of water. That is, water is often priced lower than it would be on an open market. Resolving this issue is out of scope of this work but worth noting since the option to pipe to a municipality is considered.

- Water treatment can be prohibitively expensive. Finding ways to reduce the cost of treatment (perhaps through technical innovation or government incentives such as tax breaks or subsidies) could help make some of these PW management options more attractive.

- Brine disposal via SWD is expensive in this region. Reducing the volume of brine requiring disposal could help lower the cost associated with treatment. One option is to recover some of the salts from the brine thereby reducing the volume. The salts could then be sold for road de-icing or other applications.

- Currently in the model, the option to grow greenhouse crops uses only a small fraction of the treated water and the remainder is discharged to a nearby stream. Finding additional ways to generate revenue using the treated water could help reduce the overall cost of growing greenhouse crops onsite. Another possibility is to determine whether tax incentives or subsidies might be options for discharging the excess treated water to a nearby stream thereby increasing environmental flows.

- Another possibility with respect to the greenhouse option is to analyze irrigating other crops that might be more lucrative.

While the details of the ideas listed above are mostly out of scope for this work, they serve as a potential starting point for future work and analysis. Finding a way to reduce costs for these options over the traditional options could mean an increase in implementation of nontraditional PW management strategies.

Chapter 6

Conclusions and Future Work

By examining the environmental challenges posed by dramatically increased HF in the major US shale regions and assessing possible PW management strategies at one site, this dissertation aimed to build a framework for mitigating the waste streams associated with unconventional O&G activity. These goals were addressed through the three research objectives in Chapters 3-5, and the findings are summarized below.

6.1 Summary of Results

Research Objective 1: The focus of this objective (detailed in Chapter 3) was to build a methodology for selecting an appropriate water treatment technology based on a variety of metrics accomplished in three main steps summarized below:

- A comprehensive water treatment database was built containing over seventy products and technologies across the spectrum of treatment levels. Information was gathered across 15 metrics to better understand the capability, logistics, and cost of each product or technology.
- A down-selection tool was created to allow a user to compare and rank water treatment technologies and products across the same treatment category. This tool is flexible allowing the user to adjust the metrics that are compared and even the weighting of each metric. The tool together with the vast information

provided in the technology database are a powerful combination to compare treatment technologies and products.

- The down-selection tool was then used to determine the most appropriate treatment technology when low TDS concentration is desired (i.e., used to compare tertiary treatment technologies and products) using water quality information for several shale regions. Based on the tertiary treatment technologies that were compared, MVR is often the highest ranked option due to high factor values for technology readiness level, mobility, and influent quality metrics. In the Niobrara region where the average WW TDS concentration is much lower than in other regions, RO was ranked highest.

Research Objective 2: The focus of this objective (detailed in Chapter 4) was to:

1. Compile and curate flared gas and generated wastewater associated with unconventional O&G operations in the major shale regions in the US.
2. Provide an engineering assessment of the technical potential to repurpose the energy from flared gas for treating the wastewater thereby creating a valuable commodity of treated water.

Aggregated volumes of both flared gas and wastewater were compiled and curated from a variety of sources, mainly state and federal agencies. Using the energy requirements of MVR as a benchmark, the volume of wastewater that could have been treated using the energy embedded in the flared gas was calculated by region. It was determined that the Bakken, Marcellus/Utica, and Niobrara regions had enough flared gas energy to treat all their wastewater. In fact, in 2014, these regions flared 48, 14, and 2 times the amount of energy required to treat their wastewater, respectively.

The flared gas energy in the Eagle Ford, Permian Basin, and Haynesville was sufficient to treat approximately 50, 20, and 2% of their wastewater, respectively. These numbers help highlight 1) the magnitude of the lost potential useful work embedded in the flared gas and 2) which regions flare the most both in absolute terms and on a relative basis.

Research Objective 3: This objective (detailed in Chapter 5) focused on determining the best option for managing PW (among four options) at one specific O&G site in Wyoming using a decision analysis model. The four PW management options included: piping to a municipality, irrigating switchgrass onsite, irrigating greenhouse bell peppers onsite, and discharging to a nearby stream. The analysis looked at the expected values of the PW management pathways including and excluding potential profits from natural gas sales. It was determined that all four PW management pathways are a cost center for the operator if natural gas profits are excluded (i.e., expected values are negative).

The results showed that discharging to a nearby stream, followed closely by irrigating switchgrass had the highest expected values when natural gas profits were both included and excluded. This result is likely heavily influenced by the fact that these two options have lower water treatment and brine disposal costs compared to piping to a municipality and irrigating greenhouse crops.

The expected value of discharging to a stream is less than 10% higher than irrigating switchgrass. Since the expected values are close, having more certainty around the various inputs into the model such as switchgrass price and yield along with the likelihood a permit to discharge will be approved becomes increasingly critical to aid in the decision-making process.

6.2 Future Work

There are many directions in which this work could continue and ideas left to explore. To maintain its relevance, the water treatment technology database in Research Objective 1 should be updated on a regular basis as new technologies and products are vetted, existing technologies and products are discontinued, or companies go out of business. To best achieve this outcome, the database should be made publicly available in a format where verified users are allowed to update and comment on its contents (a la Wikipedia). Similarly, refactoring the down-selection tool into an interactive, online tool that is maintained and updated as necessary will continue its relevance into the future. The lack of proper maintenance is likely why other similar online tools were unavailable at the time of this study rendering them obsolete.

Additional research and investigation focused on determining the economic feasibility of mineral extraction from O&G WW should be considered. The overall cost of water treatment could be reduced in areas containing high-value minerals if a cost-effective method of mineral recovery is achievable.

For Research Objective 2, and based on the extensive effort expended to compile and curate data on the various waste streams associated with unconventional O&G activity, a national database that streamlines and standardizes a method of reporting should be implemented across the US. Currently, well information is most often reported at the state level and, as such, is highly inconsistent since each state has its own system of reporting and even different requirements on what information must be submitted. While this would represent a massive undertaking, having a single repository for this information would mean the data are in a consistent, easy-to-digest format which is instrumental to the ability of researchers to provide timely analyses. While there are companies that compile and curate some of this information, they mostly do so to sell it to O&G companies for large fees, often leaving academic, government, and NGO researchers with few options. In addition, at the time of this study, such companies were not compiling flared gas data, which suggests an opportunity to fill a data gap important for related research. Other future work directions on this objective could include:

- To obtain deeper resolution on this issue, FG for WW should be considered on a well-by-well basis rather than on a regional level. This would require well-level data ideally on a more temporally resolved interval.
- Performing an economic analysis that incorporates logistics and regulations for using FG for WW.
- Further understand the variability in energy density of the FG by region to further dial into how much energy is being burned and lost.

Several opportunities for future work and direction for Research Objective 3, the decision tree model, were highlighted at the end of Chapter 5. The opportunities mostly involve finding ways to decrease the costs associated with the PW management strategies (primarily around reducing water treatment and brine disposal costs) or attaining closer to the maximum prices for the various commodities that might be produced.

While the analysis focuses on ways to beneficially use treated PW, future work might include other possible revenue streams by exploiting the large acreage of the site. Some possible considerations include running livestock and generating power through renewable resources such as wind, solar, and geothermal. This power could then be used for onsite demand or sold to the grid. Figure 6.1 shows a schematic of possible options for both beneficial use of treated PW and generating power onsite. These possible revenue streams could then be incorporated into the decision analysis and financial models presented in this work.

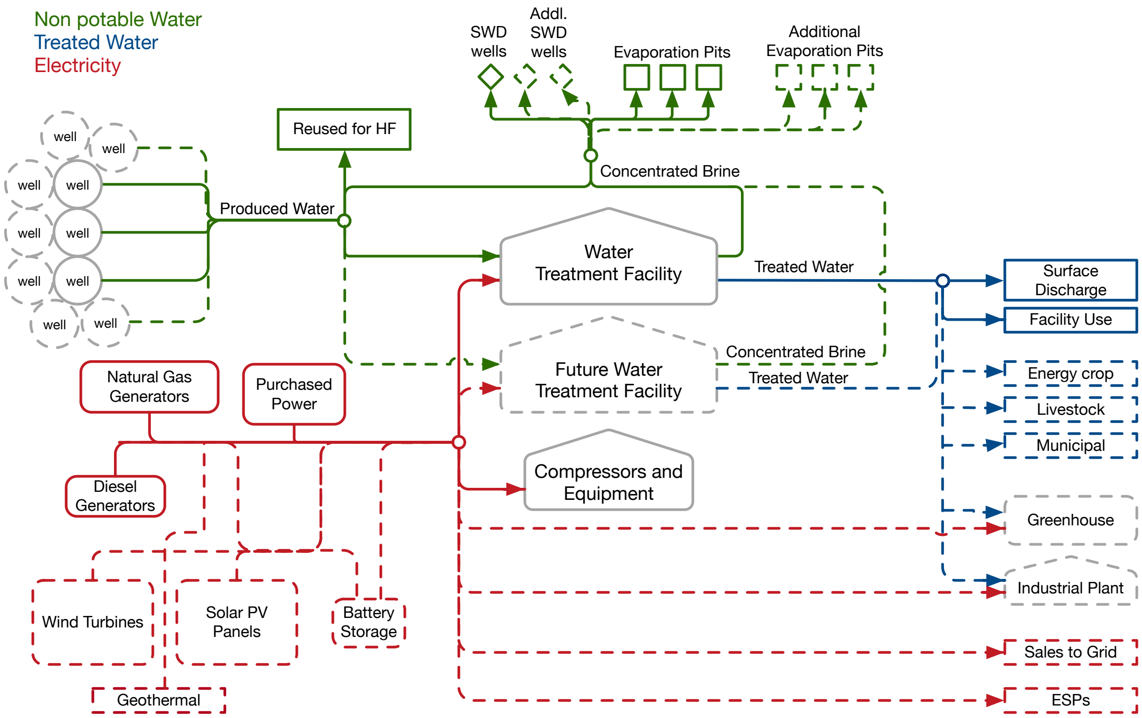

Figure 6.1: In this schematic, possible options for 1) nontraditional PW management pathways (dotted blue lines) and 2) onsite renewable energy generation and storage (dotted red lines) are overlaid on top of current operations (solid lines). Incorporating onsite power generation via renewable energy sources could be used onsite or sold to the grid. In addition to being a potential revenue stream, adding renewable energy to its portfolio could increase the operator's goodwill with the nearby communities and public at large.

6.3 Final Thoughts

The fast-paced, boom and bust nature of the US oil and gas industry means that regulations and best practices to mitigate its associated environmental liabilities often lag behind exploration and production. That said, many entities across industry, government, non-profits, and academia are vested in finding technically- and economically-feasible solutions to this sector's many environmental challenges. The advancements and learnings made in the US will likely serve as a model for other nations around the world debating whether to exploit their shale resources. Those countries have the advantage of entering this space largely prepared for the possible environmental challenges they could face. Therefore, the framework and ideas presented in this dissertation hopefully have value for the industry in the US and around the world.

Appendices

Appendix A

Tertiary Treatment Technologies

This Appendix provides additional information on the seven tertiary treatment technologies explored in Chapter 3 and listed in Table 3.3.

A.1 Mechanical Vapor Recompression (MVR)

MVR is a commonly used tertiary technology for O&G wastewater when freshwater is the end goal. It is a thermally-driven water treatment technology that feeds wastewater into an evaporative heat exchanger. The vapor phase of the influent water (now distilled water) is passed through a compressor where it becomes superheated vapor. The high temperature steam is then passed through the evaporative heat exchanger which heats the influent wastewater. The steam that exited the compressor is then condensed back to a liquid phase and recovered as distilled water. MVR appears to be the current O&G industry standard when TDS concentration in PW is greater than 50,000 mg/L and must be treated to freshwater standards (i.e. around 500 mg/L TDS concentration). Figure A.1 shows a schematic of an MVR system.[1]

This appendix was adapted from a section of a technical report prepared for an industry client authored by Yael R. Glazer and Dr. F. Todd Davidson.

[1]Figure A.1 was first published in the journal paper *An Inventory and Engineering Assessment of Flared Gas and Liquid Waste Streams From Hydraulic Fracturing in the USA* by Yael R. Glazer, F. Todd Davidson, Jamie J. Lee, and Michael E. Webber [58].

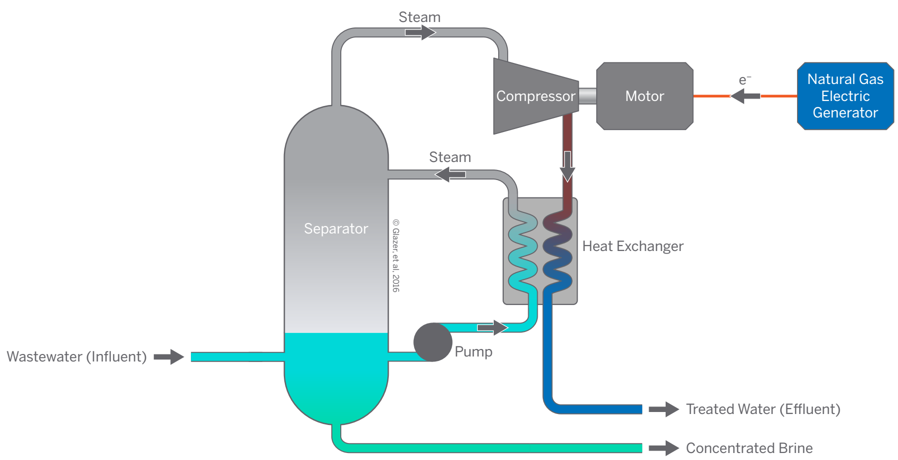

Figure A.1: A process diagram for a generic MVR system. Any water treatment technology will generate at least two outputs after treating wastewater: 1) TW that can be reused for beneficial purposes and 2) a concentrated waste stream that requires disposal or other forms of management. Under certain operating conditions, the treatment system can produce other valuable products such as concentrated salts for deicing roads or a 10-lb brine that can be used for completing maintenance on wells. This system is powered by an electric motor. [58].

A.2 Multi Effect Distillation (MED)

MED is a thermally-driven water treatment technology. The fundamental principle is to apply enough energy to boil feed water and produce steam. The steam is subsequently condensed. To increase efficiency of the system, several stages (or effects) can be used each one at a subsequently lower pressure than the one before allowing boiling to occur at lower temperatures.

A.3 Multistage Flash Distillation (MSF)

MSF is a thermally-driven water treatment technology that distills water by heating it and then using flash evaporation, a method by which water is evaporated primarily by lowering pressure instead of increasing temperature. There are often many stages where water is flashed, each comprising of a heat exchanger and condensate collector. MSF is a relatively mature and robust technology.

A.4 Carrier Gas Exchange (CGE)

Wastewater is heated and then sprayed into a column filled with crumpled material while dry air flows up through the material. The crumpled material provides a large surface area for the water to evaporate. The hot vapor is then used to preheat the influent wastewater before the vapor is recovered as distilled water. The heat exchanger used to preheat the influent wastewater uses two-phase convective heat transfer to improve the efficiency of heat exchange with the wastewater.

A.5 Reverse Osmosis (RO)

RO is a filtration method for purifying water. RO selectively removes ions from the wastewater as it passes through a membrane. The flux of the water through the membrane is driven by hydraulically induced pressure. The permeate is distilled water, and remaining fluid (with the rejected ions) is drawn off as a concentrate requiring disposal.

A.6 Emerging Technologies

Two emerging technologies were investigated for this work including membrane distillation and forward osmosis.

A.6.1 Membrane Distillation (MD)

MD is an emerging filtration method that is driven by a difference in vapor pressure between the influent wastewater and the distillate. MD utilizes low-grade heat to drive separation through a hydrophobic membrane.

A.6.2 Forward Osmosis (FO)

FO is an emerging water treatment technology that uses a semi-permeable membrane and the osmotic process to effect separation of water from dissolved solutes.

Appendix B

Factor Description for Down-Selection Process

This Appendix provides information on the factors used in the down-selection tool and their corresponding values.

Table B.1: Description for the technology readiness level metric using the API 17N scale [1, 2].

Factor Value	TRL Description
0	Unproven concept. Basic R&D, paper concept. No analysis or testing has been performed.
1	Concept demonstrated. Basic functionality demonstrated by analysis, reference to features shared with existing technology or through testing on individual subcomponents/subsystems.
4	Technology qualified for first use. Full-scale prototype built and technology qualified through testing in intended environment, simulated or actual. The new hardware is now ready for first use.
7	Proven technology. Technology integrated into intended operating system. The technology has successfully operated with acceptable performance and reliability within the predefined criteria.

Table B.2: Description for the mobility metric.

Factor Value	Mobility Description
1	Large, fixed, non-skid mountable (immobile) plant
4	skid mounted, take down/set up within 1-2 weeks
7	Skid mounted, can fit easily on a trailer, take down/set up less than 2 days

Table B.3: Description for the effluent quality metric.

Factor Value	Effluent Quality
0	No treatment
1	Natural settling
2	floc & drop and coarse filtration, minimal TDS change
3	Micro filtration and chemical & biological treatment
4	Nano filtration
5	TDS of 501—3000
6	TDS of 150—500
7	TDS of <150

Table B.4: Description for waste stream metric.

Factor Value	Effluent Quality
0	Solid waste—landfill
1	> 50% waste fraction (liquid)
3	16—50% waste fraction (liquid)
5	6-15% waste fraction (liquid)
7	=< 5% waste fraction (liquid)

Table B.5: Description for cost metric.

Factor Value	Cost (\$/bbl wastewater)
1	> 5
4	2—5
7	< 2

Table B.6: Description for energy intensity metric.

Factor Value	Energy Intensity (kWh/m^3)
1	> 100
4	10—100
7	< 10

Appendix C

Industry Representatives Interviewed & Survey Questions

C.1 Industry Representatives and Stakeholders Interviewed

Please note that while people from each of the entities listed below contributed to the information provided in Appendix D, they have not reviewed nor do they necessarily agree with the findings.

1. 1804 Operating*
2. Aethon Energy
3. Anadarko Petroleum Corporation
4. Apache Corporation
5. Bureau of Economic Geology, University of Texas at Austin
6. Callon Petroleum
7. Center for Sustainable Shale Development
8. Chesapeake Energy*

The information provided in this appendix is adapted from sections of an internal report delivered to the United States Department of Energy on September 30, 2016 under Contract Number:DE-EP0000011 that was authored by Yael R. Glazer, F. Todd Davidson, Jamie J. Lee, Gordon T. Tsai, and Michael E. Webber.

9. Chevron*
10. Concho Resources
11. Conoco Phillips*
12. Department of Energy
13. Diamondback Energy
14. Environmental Defense Fund
15. General Electric
16. Gradient Corporation
17. Guidon Energy
18. Kinder Morgan
19. Laredo Petroleum
20. Newfield Exploration
21. North Dakota Industrial Commission
22. Oilfield Water Logistics*
23. Orion Water*
24. Penn Virginia*
25. Permian Basin Water Management Council
26. Pioneer Water Management and Power

27. Purestream Services*
28. Railroad Commission of Texas
29. Range Resources
30. SeaChange Technologies, LLC
31. Stanford University
32. Statoil
33. Texas Commission on Environmental Quality
34. Texas Farm Bureau
35. Texas General Land Office
36. WaterLens
37. X-Chem, LLC

* Entities were interviewed in greater detail using the questions provided in the next section.

C.2 Survey Questions

- Do you flare?
  - Do you monitor flared gas volumes? If so, what are typical volumes (e.g. mmscf/day)?
  - Is the information on flared gas volumes reported to the state/government?
  - Do you pay royalties and/or taxes on flared gas?

  - How much of NGL's are being separated from the C1-C7 gases before being flared?
  - What is the composition of the natural gas being flared?
  - Are the NGL's being sold? (mostly for Bakken)?
- What do you do with your WW?
  - Where and how is the WW disposed?
  - What are the costs associated with disposal?
- Do you treat your WW?
  - What percentage of the WW is treated versus disposed?
  - What is the treated water used for?
  - What treatment technology/ies do you use? Done in-house or vendor-provided?
  - What are the costs associated with treatment?
- Sourcing of "fresh" water/ water for operations
  - Where does the water come from? E.g. ground water/surface
  - Is it trucked or piped to the location?
  - How much does water cost?
- Other infrastructure
  - Are gas pipelines abundant and accessible for you?
  - If not, are there plans to get pipelines installed? What is the general timeline until that is completed?

    - Do you have power lines giving you access to the grid?
        * If not, do you have on-site power generation using diesel? Generation using natural gas?

- Market Barriers (for WW treatment?)
    - Price constraints
    - Lack of service providers

- Regulatory Barriers
    - Legislation restricting beneficial use of treated WW?
    - Any other regulatory barriers slowing the adoption of environmentally beneficial practices?

Appendix D

Additional Information on Shale Regions of Interest

To help inform the analysis conducted in Chapter 4 and to better understand current water management and flaring practices in the oil and gas industry, operators and service providers from various shale formations across the US were consulted, including the Bakken, Marcellus, Eagle Ford, and Permian Basin. In total, resource management practices, regulations, and economics were discussed with 37 different entities, including super-major oil and gas companies, academic experts, state and federal regulators, as well as small service providers who operate in the field (a list of entities is provided in Appendix C). One of the entities was the Permian Basin Water Management Council which was, at the time, comprised of 29 operators and service companies that provide members the opportunity to collaborate and share best practices for both water sourcing and WW management. In general, interviewees were forthcoming and open to share information but wanted to remain off-the-record. As such, no information presented in this chapter is associated with the name or company of any interviewee. A common theme that emerged in these conversations is that many operators in 2016 were scaling back on treating their WW due to challenging market conditions (i.e. decline in global oil prices) that began in 2014 and persisted through

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2016. Many operators are disposing via SWD wells to manage their WW rather than treating the water to a higher standard than needed for underground injection.

The following sections synthesize details learned that are specific to the various shale regions during interviews conducted in 2015 and 2016. These notes are general in nature, and specific practices can vary among operators in a single region. Appendix C contains questions used to facilitate interviews with a subset of the interviewees.

D.1 Bakken

Water Management Practices: Freshwater for HF can typically cost less than $1 per barrel of water in the Bakken region, excluding the cost of transportation. The greatest cost for managing water in the Bakken is often associated with transportation.[1] The majority of water, whether fresh or waste, is trucked to and from the wells rather than piped. Based on interviewee responses, the economic viability of water pipelines in the region is limited and is very dependent on the unique needs of each case. However, given sufficient volumes of water some companies are expanding their efforts to build and acquire dedicated water infrastructure in other regions, which might impact practices in the Bakken [103].

There are an abundance of saltwater disposal wells in the Bakken. Depending on how far an operation is from these wells, transportation costs range from $0.50 to $4 per barrel of WW. WW in the Bakken is extremely dirty compared to other regions, with TDS concentrations upwards of 200,000 mg/L (compared to an average of 40,000 mg/L in the Eagle Ford) [30, 31]. Thus, treatment to freshwater standards appears impractical in the region.

Flaring Practices: Flaring is a relatively common practice in the region since

[1]Interview with Subject Matter Expert

the development of unconventional oil and gas operations. As of July 2016, operators in North Dakota are permitted to flare for a year from the date of first production of the well before being required to set up infrastructure to handle the gas, which includes actions such as putting in natural gas pipelines or setting up an electric generator to utilize at least 75% of the natural gas from the well to reduce flaring. If these rules are not met the operators might be required to pay the mineral rights owner royalties on the flared gas and the state a gross production tax despite the fact that the flared gas is never sold [104]. If oil and gas wells use a system to avoid flaring, such as the actions described above, gas from these wells is exempt from the gross production tax for two years and thirty days from the time of first production [105]. In April 2014, the North Dakota Industrial Commission (NDIC) stated that they were considering amending current field rules in the Bakken to restrict oil production to reduce the amount of flared gas [106].

As mentioned in Section 4.6.1 of Chapter 4, the rate of flaring in the Bakken has declined significantly from 2014 to 2016 likely due to 1) decline in oil prices and subsequent decline in drilling operations and 2) regulations set by the NDIC to reduce flaring. The NDIC established targets for the percentage of natural gas produced that could be flared: 20% for April through October 2016, 15% for November 2016 through October 2018, 12% for November 2018 through October 2020, and 9% following November 2020.

The Bakken's natural gas pipeline infrastructure is not as fully developed as other regions (such as the Permian Basin). In 2012, approximately 40% of wells were serviced by pipelines in the Bakken area, and in 2015 that increased to 60%.[1] To capture the larger volumes of associated gas produced during the early stages of operation, natural gas pipelines need to be connected to the oil and gas wells from start of production. The economic value of gas pipelines can decline significantly if the large volumes of associated gas at the beginning of production are not captured.

Additional Information: The Bakken has widespread electrical distribution, giving operators abundant access to the electrical grid. Subsequently, there has been little to no onsite power generation using natural gas. Electricity is controlled by co-ops, who sell the operators power at approximately $0.11/kWh, under one example from an interviewee. This price was considered high based on prevailing electricity prices for industrial customers in the region.[1] And, yet, $0.11/kWh is low enough to discourage wide-spread use of onsite power generation using natural gas.

D.2 Marcellus and Utica

Water Management Practices: Treatment is viewed favorably by operators and regulators, due in part to the lack of disposal wells in Pennsylvania. As of 2015, the state had seven active deep injection wells for oil and gas waste, with three more permitted but inactive [25]. According to a report released by Chesapeake Energy, Pennsylvania does not have favorable geology for subsurface disposal wells [107]. Regulations limiting the practice of deep well injection in combination with unfavorable geology make it unlikely that more disposal wells will be built in the future.

Many operators transport WW by truck to neighboring states, such as Ohio, for disposal. Transporting WW in the region can cost upwards of $6.00 per barrel of water [31]. Furthermore, prices have fluctuated frequently in the years prior to 2016, likely due to the lack of water trucking companies in the region as drilling operations expanded significantly. The high, fluctuating prices for transportation has made trucking an unfavorable option, despite the necessity to move the water. As a result, some operators are trying to move away from using trucks, which has caused some concern for job losses in the trucking and transportation industry.[1] At the time of the interviews, many operators were considering installing additional water pipelines, including flexible hoses (sometimes referred to as lay-flat pipes) Some small operators were collaborating to create shared infrastructure, including water and gas pipelines, which might help drive down the costs associated with treatment, disposal, and transportation.

Many operators treat their WW onsite using oxidizers and biocides within large water tanks. This level of treatment is often sufficient for reuse on a subsequent well completion. Desalination is less common due to the high cost. These operators try to treat and reuse as much of the produced water as possible; flowback water is more likely to be trucked for disposal because it can contain more of the fluid used during hydraulic fracturing and can be harder to treat.

Some specialized treatment facilities exist, such as Eureka Resources, and have permits for surface discharge following proper treatment of the WW.

Flaring Practices: The Marcellus is predominantly a gas play, so operators set up natural gas pipelines before production begins, leading to minimal flaring in the region compared to the amount of natural gas produced. Despite the expansive pipeline network, the large gas production volume means that some flaring does still occur.

D.3 Eagle Ford

Water Management Practices: While no official regulations have been implemented regarding WW treatment, the Railroad Commission of Texas (RRC) has encouraged operators to reuse treated WW not just from oil and gas operators but also municipal waste treatment plants [108]. Despite these efforts, the majority of WW is still trucked or moved via pipeline to disposal wells. Due to the abundance of disposal wells, disposal costs are relatively low (typically around $1-$2 per barrel of WW) since WW does not have to be transported far for disposal.[1] Operators in the area have attempted to treat WW to freshwater standards, producing a concentrated brine as a byproduct with approximately 250,000 mg/L TDS concentration, which is often referred to as a 10-lb brine. In certain regions, such as the Eagle Ford, 10-lb brine can be used to temporarily stop a well from producing (termed killing a well) to allow for maintenance. 10-lb brine is a valuable commodity and can be sold for approximately $1.50 per barrel to other operators in the region. As such, it helps make desalination water treatment technologies more economically appealing in the Eagle Ford by producing multiple sources of revenue or cost savings. However, low oil prices led to significant decline in drilling operations and thus reducing the market for 10-lb brine. As a result, it does not appear to be economical to use tertiary treatment technology in the Eagle Ford as of July 2016.

Freshwater can cost approximately $0.25 per barrel of water, which is often paid to the landowner because of contractual restrictions that prevent operators from seeking outside water sources. This cost excludes transportation (approximately $1.15 per barrel) and impoundment of the water. The cost for constructing impoundments can range from $200,000 to $1,500,000, depending on the desired capacity.[1]

Operators use electricity from the grid when they can; because of the large amount of electricity needed, some operators will pay to construct dedicated transmission lines, rather than connecting to the same power source as nearby homes. Of those who use onsite generators, they typically use their own produced natural gas to power the generators.

Flaring Practices: Flaring is often limited to gas that has accumulated within oil storage tanks, sometimes referred to as flash gas. Operators will often build or contract others firms to construct sufficient infrastructure, including pipelines, so that oil and gas can be collected when production begins.[1] Many operators only flare flash gas. Unfortunately, the volume of gas flared from oil storage is not reported. However, in instances where associated gas is flared it is reported to the RRC. The operator pays royalties and taxes on flared and vented gas (at the same rate as gas that would have been sold on the market) to the mineral rights owner and to the state, respectively. The operators do not, however, pay royalties or taxes on flash gas that is burned.

D.4 Permian Basin

Water Management Practices: Due to declining oil prices, fewer operators are treating their WW in 2016 than a few years ago, similar to the Eagle Ford. Depending on the size of the operation, the amount and fraction of WW being treated and recycled varies. Large operations recycle only 1-2% of their total WW (treating 10,000 barrels per day), while smaller operators recycled as much as 90% of their produced water (treating 2500 barrels per day).[1] One major operator has been minimally treating as much of their produced water as possible (80-90%) for reuse. For the most part, larger operators appear less likely to treat their WW to freshwater standards for the purpose of beneficial reuse. This trend is partially due to unknown liabilities surrounding the long-term effects of using treated water for municipalities and agriculture. While trucking is currently a common method for transporting water, some operators are moving toward pipelines connected to disposal wells, including lay-flat pipeline. One service provider in the area moves WW from operations to disposal wells for $0.45-1.00 per barrel.[1]

Flaring Practices: The Permian has well-developed gas pipeline and processing infrastructure as a result of legacy hydrocarbon production. Thus, operators rarely flare a significant amount of gas from individual sites; in 2014, only 2% of all natural gas produced in the Permian region was flared [109].

Appendix E

Wastewater Treatment Technology Product Database

This appendix contains the treatment technology database in its entirety split up by technology/product type. As mentioned in Chapter 6, for the database to maintain its relevance, it should be updated on a regular basis as new technologies are vetted, products are discontinued, companies go out of business, etc.

A dash line, "–" was inserted where information was not found about a technology or product. Rows that are shaded indicate the technology or product is no longer available as of this work.

In addition to technologies and products that aim to treat the wastewater to varying levels, there are companies that focus on extracting potentially valuable minerals. Enviro Water Minerals Company(EWM) and MGX Minerals are two such companies.

Table E.1: Primary Treatment Technologies and Products

Technology Name	Technology Type	Vendor/Owner	Capacity, m3/d	Mobility	Costs $/bbl	Feed water quality, ppm	Treated water quality, ppm	Waste fraction,v/v%	Consumables	Power supply	TRL	Current Region of Operations	References/Notes
MoTreat System	–	Aquatech	715	mobile	1-4 (in TX approx. 1)	800-1000 TSS	<50 TSS; softening possible; <0.5 ppm Fe	0.5-2.0%	Metal salt, polymer, lime for softening	30-40kW for only MoTreat and about 50-60 kW for compressor. Can use nat. gas onsite	7	Permian Basin, Pennsylvania	–
Ecologix Mobile ITS	dissolved air flotation	Ecologix Environmental Systems	4900	semi-mobile	1-3	–	99% removal	<2%	Metal salt, polymer	–	7	Eagle Ford, Canada	EC can be incorporated http://blog.ecologixsystems.com/recyclin-frac-water-in-texas/
EcoSeparator	pressurized centrifugal system	EcoNova	545	mobile	–	<0.5% by volume TSS; <100,000 TDS	–	Metal salt, polymer	–	60 Hz, 100 A	3	Uinta Basin	http://www.econovainc.com/newsite/wp-content/uploads/2015/02/EcoSeparator.pdf
IGF	induced gas flotation	Purestream Solutions	600 per cell (can scale to 1200)	mobile	0.42 (operational cost)	250-500 TSS	<50 (regular<10)	1-3%	Metal salt, polymer	15 kW, ~1 kWh/m3; unmanned, uses 50 A for intermittent pumps	7	Permian Basin	Unmanned operation
MAGNA MWTS	dissolved air flotation	Sionix Corporation	4500	stationary	–	–	–	–	Metal salt, polymer	–	–	–	http://www.sionix.com/technology/DAF
AutoFlot	Static Flotation Separator (Induced Gas Flotation)	Veolia Water Technologies	up to 11,760,000	–	–	–	>95% oil removal	–	–	–	–	–	http://www.veoliawatertech.com/vwt-latam/ressources/files/1/49320-AUTOFLOT.pdf
StreamlinerTM	hydrocyclone	Veolia Water Technologies	–	–	–	up to 1000 free oil	40-60 free oil	–	–	–	–	–	http://www.veoliawatertech.com/en/news-resources/articles-technical-papers/deoilinghydrocyclones.htm
Multiflo Softening Technology	chemical precipitation	Veolia Water Technologies	1500	mobile	–	–	<30 TSS; <50 CaCO3	<5%	Metal salt, polymer, lime for softening	–	7	Across the globe	Scale-removing http://www.veoliawaterstna.com/news-resources/information-files/mobilemultiflo.htm;http://technomaps.veoliawatertechnologies.com/processes/lib/pdfs/2730,Brochure_multiflo_2013_EN_draft_v07.pdf
ROSS	ceramic membrane, Multiflo Softening Technology	Veolia Water Technologies	795	mobile & stationary options	–	10-300 TSS; 3-80 Fe	<0.2 TSS; <0.5 Fe	0.02	–	–	3	Utah	Provided as a service http://www.wateronline.com/doc/the-ross-system-ceramic-membrane-based-produced-water-treatment-0001;http://www.veoliawatertechnologies.com/sites/g/files/dvc471/f/assets/documents/2015/01/25194O-G-ROSS-4-10b.pdf; http://www.veoliawatertech.com/en/news-resources/datasheets/ross-flowback-produced-water.htm
SCE (for pretreatment before CGE)	Selective Chemical Extraction	Gradiant	–	mobile	–	–	–	–	–	–	6	Permian Basin	Combined with CGE (Tertiary Treatment)
Rover System	clarification, flocculation	Fountain Quail Water Management	1600	mobile	0.9-1.5	–	<50 TSS; softening possible	<5%	Metal salt, polymer, lime for softening	75 kW	–	Permian Basin, Eagle Ford	–
OvivoSep CPI	Corrugated Plate Interceptors	Ovivo	–	–	–	–	<5 oil	–	–	–	–	–	http://www.ovivowater.com/product/energy/oil-and-gas/produced-water-primary-treatment/cpi/ovivo-sep-cpi/
FracTreat MF Mobile Flotation	–	Siemens	3200	–	–	<600 oil	–	–	Metal salt, polymer	–	–	–	Siemens sold this technology to Evoqua who no longer offers it.
FracTreat Mobile Precipitation	–	Siemens	540	–	–	–	–	0.5-2.0%	Metal salt, polymer	208 VAC, 60Hz, 50A	–	–	See above
CoMagTM	flocculation, coagulation, clarification	Siemens	500	stationary	–	Total phosphorus 1	Total phosphorus 0.2	–	Metal salt, polymer, magnetite	–	4	Massachusetts, New Hampshire, West Virginia	http://www.evoqua.com/en/brands/Envirex/Pages/comag.aspx

Table E.2: Primary Treatment cont.

Technology Name	Technology Type	Vendor/Owner	Capacity, m3/d	Mobility	Costs $/bbl	Feed water quality, ppm	Treated water quality, ppm	Waste fraction,v/v%	Consumables	Power supply	Technology Readiness Level (TRL)	Current Region of Operations	References/Notes
H2prO HMS	electrocoagulation	Baker Hughes	1015	mobile	2	–	99% removal of TSS and heavy metals; significant reduction of Fe (<10 ppm) and hardness	–	–	–	7	Texas, New Mexico	Approximately $20,000 saved compared to not treating the water due to reducing trucking `http://www.bakerhughes.com/capabilities/water-management/water-management-solutions/water-management-surface/h2pro-hms-water-management-service`; Seem to be provided as a service
Ozonix	ozone oxidation, acoustic and ultrasonic cavitation, electrocoagulation	Ecosphere	18000	mobile	1.25	–	100% bacteria and scalants	0	–	600 kW	7	US, Canada, Brazil, Malaysia	`http://www.ecospheretech.com/environmental-engineering-technologies/ozonix`
CleanWave	electrocoagulation	Halliburton	4500	mobile	1-3	<300 000 TDS	<5 TSS; 95-99% reduction of: bacteria, H2S, heavy metals, oil	3-5%	–	480 VAC, 3 phase, 60 Hz, 175/200 A	4	Utah, Haynesville	`http://www.halliburton.com/en-US/ps/stimulation/stimulation/water-solutions/cleanwave.page?node-id=h8cyv98a\#`
NeoFracTM, now Rockwater Mobile Water Treatment	electro-oxidation, clarification	NeoHydro, acquired by Rockwater Energy Solutions	1600	mobile	3-4	–	99.9% reduction of bacteria; 99% removal of TSS; 30% removal of metals	–	Acid/base for pH adjustment	80 kW	4	Uinta Basin	`http://www.bizjournals.com/houston/blog/drilling-down/2014/07/houston-energy-company-buys-local-water-treatment.html` offered as a service `http://www.rockwaterenergy.com/fluids-conditioning/`
Powell EC System	electrocoagulation	Powell Water Systems	units range from 9 to 3270	semi-mobile	0.89 (operational in Colorado)	400-260,000 TDS	99% TSS and silica. Effective reduction of oil, hardness, bactera, btex	<5% (literature) <1% (interview)	Iron blades dissolve, acid wash for cleaning	2-7 kW/1000 gal	7	California, Indonesia	Will provide quote if given water sample sheet
Frac Flowback Water Treatment	oxidation	PPC (Process Plants Corporation)	–	–	<4	–	99% TSS; 94-97% of minerals	–	–	–	4	Marcellus	–
EcoRenew	electrocoagulation	Water Rescue Services Holding	6400	mobile	1.65-2.10	–	<6 NTU; <1 Fe; significant reduced hardness and bacteria	<5%	filters	125 kva	6	Permian Basin, Eagle Ford, Barnett	Allows contaminates to form flocks that can settle out
Clear H2O	electrocoagulation	Advanced Waste & Water Technology, Inc.	–	–	–	–	–	–	–	–	–	–	`http://awwtinc.com/electrocoagulation/clear-h2o-method/`
WaterIonics	electrocoagulation	WaterTectonics	–	–	–	–	–	–	–	–	–	–	`http://www.watertectonics.com/technology/waveionics/`
Electro Precipitation (EP) technology		Latitude Clean tech Group	4500				>90% TSS; >95% bacteria and iron; 100% heavy metals; variable on scalants, oil	<3%	–	–	–	–	No working website, phone, or email
EcoEC	electrocoagulation	EcoNova	140	–	–	–	–	–	–	–	–	–	–

Table E.3: Filtration and Polishing Technologies and Products

Technology Name	Technology Type	Vendor/Owner	Capacity, m3/d	Mobility	Costs $/bbl	Feed water quality, ppm	Treated water quality, ppm	Waste fraction,v/v%	Consumables	Power supply	Technology Readiness Level (TRL)	Current Region of Operations	References/Notes
FilterSure	filtration	FilterSure Inc	680	mobile	2.5	300-500 TSS	75-100% hydrocarbons; 95-100% >3 micron; 100% bacteria	<1%	Compressed air	135 kW, 120 VAC, 10 A	–	–	http://www.filtersure.net/industrial_installations_mobile_systems.htm
Aqua-VesTM	membrane distillation	National Oilwell Varco, Fluid Control	400	mobile	1.3-1.8	<50% solid; TSS removal amount dependent on percentage of water	NTU <5; 100% bacteria; 0.05 microns; <600 TSS	<5%	Membrane cleaning chemicals; cleaning cycle every 24 hrs; 28 bbl freshwater per clean	0.27kWh/kgal; 150 kW generator	5	Wyoming	requires pretreatment https://www.nov.com/News_and_Events/News/Archived/2013/NOV_Wins_2013_World_Oil_Awards(1).aspx
High Purity Membrane Filtration	filtration	Layne Christensen	–	–	–	–	–	–	–	–	–	–	http://www.layne.com/en/technologies/membrane-filtration.aspx?mid=539
Treo	filtration	TIGG	820	mobile	–	–	–	–	–	–	5	Arkansas, Pennsylvania	multi-media filtration http://www.tigg.com/Treo-multi-media-filter
TSS Separation Solution		TSS Total Separation Solutions, LLC	34000	–	–	–	–	–	–	–	–	–	No response, website, or active employees found.

Table E.4: Tertiary Treatment Technologies and Products

Technology Name	Technology Type	Vendor/Owner	Capacity, m3/d	Mobility	Costs $/bbl	Feed water quality, ppm	Treated water quality, ppm	Waste fraction,v/v%	Consumables	Power supply	Technology Readiness Level (TRL)	Current Region of Operations	References/Notes
Altelarain 750	Thermal distillation	Altela Inc	119	stationary	$5.29/bbl, 4.88/bbl for OPEX. Contacted but was unwilling to provide information unless we disclosed clients and other technologies we're investigating.	–	<250 TDS	0.1	Polypropylene plastic	460V 3-phase @ 65 RLA/75 FLA; 110V single phase @ 15 RLA/60 FLA; 120 MCF of natural gas and 1400 kWh of electricity per 24 hour day	–	–	Brochure on AltelaRain 750 - reuses latent heat of condensation
MoVap System	MVR	Aquatech	290, scaleable	mobile	Service: $6-7/bbl (job-specific approach), energy: $0.30-0.40/bbl	≤140,000 TDS	<500 TDS	feed: 130-140,000 TDS - 50%, 30-50,000 TDS - 70%	Anti-scalant	300-350 horsepower	7	Permian Basin, Pennnsylvania	Pretreat with MoTreat and/or MoFeed. Water has been processed by MoTreat and MoFeed to yield service conditions: pH = 5.0 - 8.0; chlorides = 25,000 - 100,000 ppm; TDS = 5 - 12%; TSS <50 ppm
Mobile Frac Evaporator	MVR	GE	275	mobile	Contacted and following up	50000-150000 TDS; low sulphate, oil, iron, manganese; <100 TSS	TDS: <50 mg/L; Non-volatile organics: <1 mg/L	Dep on feed TDS; brine <285 000 TDS; 5%	Acid, caustic for CIP	295 kWh at feed 30oC	–	–	–
VAPCO	MVC (Boil then recover latent heat)	MPI	20	stationary	0.8; energy (CA): $0.21/hr for 4 m3/d	50,000 - 100,000 TDS	<5 TDS	0.1	None	30 kW/1000 gal	5	–	No international work
AVARA	MVR	Purestream Solutions	400	stationary	Service: $3-4	≤200,000 TDS; low TSS	–	Dep on feed TDS; brine <250 000 TDS; S. Texas: 70,000 TDS – 25%, Central Arkansas: 30,000 TDS –15%	Scale inhibitors, salt dispersants, defoamer; bleach	300 kW (can use nat. gas onsite)	7	Central Arkansas, Wyoming, and South Texas	Pretreat with IGF
PaxPure	desalination	PAX Scientific	–	–	–	–	–	–	–	–	3	–	http://www.paxpure.com/\#/welcome
CGE	Carrier Gas Extraction; HDH (humidifcation & dehumidification)	Gradiant	1910	mobile	Contacted multiple times, but no response	120,000 mg/L TDS	<100 ppm salinity	0.15	–	1 kWh/m3	6 (with SCE)	Permian Basin	http://newsoffice.mit.edu/2015/cheaper-fracking-water-treatment-0716; http://gradiant.com/produced-water-project-expansion-complete/; Can treat to different levels (freshwater, clean brine, 10 lb brine). Pretreat with SCE
E5H	MVR Crystallizer	Epiphany Water Solutions	0.19/container	mobile	varies - CAPEX - $50,000 (30% tax credit). OPEX, Solid disposal cost, maintenance, fuel cost (nat. gas on well pad is normally free) - $2-5/bbl; cost effective against trucks; northwestern PA: $10/bbl	250,000 ppm	<500 TDS	80% for all TDS levels	filter that needs to be cleaned and replaced eventually	hybrid of concentrated solar power (CSP) and natural gas	7	Marcellus	http://www.epiphanyws.com/produced-water/
HYDRA-CLAIM	Forward osmosis	National Oilwell Varco, Fluid Control	636	stationary	New tech, cost not set	150,000 TDS	<500 TDS	–	–	1.3-1.5 MW start-up; 580-750 kW during operation	4	Permian Basin	Companion pretreatment chemical precipitation system to remove scaling ions prior to final treatment by HYDRA-CLAIM. http://www.nov.com/Segments/Wellbore_Technologies/WellSite_Services/Water_Services/Water_Filtration/HYDRA-CLAIM_Water_Treatment_System.aspx
Electrochemical Nano Diffusion (END)	Desalination, electrochemical battery/fuel cell	Magna Imperio (MI) Systems	68	–	–	–	20-100 TDS	0.1	None	0.38 kWh/m3 of water (PRODUCES up to 1.25 kW/1000 gal freshwater - net of consumption)	–	–	Patents: 1) apparatus and methods for treating water and generating electrical power; 2) apparatus for generating electrical power; 3) apparatus and methods for generating electrical power. Electricity generated within the system.
Green Machine	forward osmosis	HTI (Hydration Technology Innovations)	916	mobile	–	–	–	–	–	–	4	Haynesville	http://www.htiwater.com/divisions/oil-gas/lead_story.html
NOMAD	MVR	Fountain Quail (previously owned by Aqua-Pure)	365	mobile	$3-5/bbl (includes transportation, power consumption, and labor); $3/bbl to treat only, $3.50 for large facilities, 6.25/bbl for small facilities, $2/bbl larger facilities	<100000 TDS	30-150 mg/L TDS, fresh water, treated 21.5 million bbls by May 2014; from RPSEA, distillate averaged 171 mg/l, median 103 mg/L, 179 mg/L st. dev.	Dep on feed TDS; 5-25%	–	–	–	–	SPE 157532 is a VERY GOOD reference on technical and economical feasiblity
ClearFlo Membrane Brine Concentrator	forward osmosis	Oasys Water	–	–	–	103000 TDS	700 TDS	<10%	–	–	6	Permian Basin, Marcellus	Can use solar, geothermal, and waste heat for energy http://oasyswater.com/solutions/case-studies/

Table E.5: Tertiary Treatment Technologies and Products cont.

Technology Name	Technology Type	Vendor/Owner	Capacity, m3/d	Mobility	Costs $/bbl	Feed water quality, ppm	Treated water quality, ppm	Waste fraction,v/v%	Consumables	Power supply	Technology Readiness Level (TRL)	Current Region of Operations	References/Notes
PFO+RO	forward osmosis, reverse osmosis	Porifera	7	–	–	32000 TDS	–	–		–	–	California (US Military)	
Neptune Treatment Facility	reverse osmosis	GE	3785	stationary	0.65	7500 TDS	250 TDS	0.1	–	–	6	Bakken	Operating in Moneta Divide
HERO	reverse osmosis	GE	9600 (max)	–	–	–	–	2-10%	–	380 V, 50 Hz, 3-phase	–	–	–
Aqua4	Concentrated Solar Still (CSS)	WaterFX	246	semi-mobile	–	100000 TDS	–	–	–	400 kW	–	California	`http://waterfx.co/aqua4/` Uses solar energy primarily
Saltmaker Evaporator Crystallizer	multi-effect distillation	Saltworks Technologies	100-400	mobile	2-3 (for smallest capacity; CAPEX and OPEX)	173000 TDS	400 TDS	0.01	–	–	6	Texas, British Columbia	Zero-liquid discharge `http://www.saltworkstech.com/wp-content/uploads/2015/02/Saltworks\_Case-Study\_Shale-Gas-Produced-Water\_EN.pdf` (case study)
OPUS II	reverse osmosis	Veolia Water Solutions & Technologies	109	mobile	–	2200 TDS	<15 TDS	<10%	–	–	–	–	`http://technomaps.veoliawatertechnologies.com/processes/lib/pdfs/productbrochures/key\_technologies/2471,OPUSII\_brochure.pdf`
GE Electrodialysis Reversal	electrodialysis reversal (EDR)	GE	5700 (max)	semi-mobile	–	100-3000 TDS (Maximum 12000)	50-95% salt removal	–	–	Stage 1: 590VDC, 26A; Stage 2: 518VDC, 14A; Stage 3: 420VDC, 7.5A	7	Korea, Spain	`https://www.gewater.com/products/electrodialysis-reversal-water-treatment`
–	desalination	SeaChange Technologies	–	–	–	–	–	–	–	–	–	–	seachangetechnologies.com (website under construction as of 08/26/2016)
EVRAS	evaporative reduction and solidification	Intevras Technologies LLC	–	–	–	The technology is not sensitive to the level and type of brine. 310,000 mg/L	no product water though...	–	–	–	–	–	NO LONGER OFFERED
PYROS	–	TSS Total Separation Solutions, LLC	1600	–	–	–	–	50%	–	650 hp	–	–	No response, website, or active employees found.
Altelarain 600	Thermal distillation	Altela Inc	380	stationary		195,000 TDS	<100 TDS	25% overall & <1% of salt	–	Used 0.540 MCF Natural Gas/bbl of water eliminated; 416 lb/hr of steam to power 10 towers & 0.485 MCF & 3.1 kWh	5	–	1) Bruff, 2011; 2) SPE 149466; 3) netl.doe.gov; 4) Bruff, 2010 - counter-current heat exchange
Altelarain 4000	Thermal distillation	Altela Inc	15-16	mobile		>40,000 TDS	20 TDS	0.1	Industrial waste heat or well-site flash gas to generate atmospheric pressure steam	110V (from generator or solar panels) and low-grade heat (from industrial waste heat or well-site flared gas) to generate steam	7	New Mexico	Godshall, 2006; does not require pretreatment - reuses latent heat of condensation
SubCom	thermal distillation	Logic Energy Solutions	750	mobile	Leasing program - cost not set	≤300,000 TDS	500 TDS	<5%	None	24V; Nat gas needed for burner.	6	Oklahoma	`http://logicenergysolutions.com/the-logical-solution/equipment/`; can recondense the water vapor if economical, but for many places freshwater is cheaper than trying to recapture the steam
GAS (GeoPure AdvancedHydro Systems)	RO	GeoPure HydroTechnologies	1200	mobile	1.5-3.5	<65000 TDS	<1000 scalants; 100% other	10-70%	Acid, base, coagulants, flocculants	2 kWh/m3	–	–	–

Table E.6: Oxidation and Disinfection Technologies and Products

Technology Name	Technology Type	Vendor/Owner	Capacity, m3/d	Mobility	Costs $/bbl	Feed water quality, ppm	Treated water quality, ppm	Waste fraction,v/v%	Consumables	Power supply	Technology Readiness Level (TRL)	Current Region of Operations
H2prO HD	ClO2 (chlorine dioxide) oxidation	Baker Hughes	24000	mobile	–	–	Depending on separation unit	Generate sludge (oxidation/coagulation)	Sodium hypochlorite, hydrochloric acid, sodium chloride	–	7	Eagle Ford, Barnett, Permian Basin
CleanStream	UV light	Halliburton	23000	mobile	–	"clean water/brine"	99.9% bacteria	–	–	–	–	Haynesville, Marcellus
MIOX HYPO	sodium hypochlorite	MI Swaco/Schlumberger	25000	–	–	–	–	–	NaCl	480V, 500A, 415 kVA	–	–
SabreSMART	ClO2	Sabre Energy Services	11130	mobile	–	–	Depending on separation unit	Generate sludge (oxidation/coagulation)	Sodium hypochlorite, hydrochloric acidm sodium chloride	–	–	–
MAVREX (formally Fractar)	ClO2	Fountain Quail	79200	mobile	–	–	99% kill bacteria	–	–	–	–	–
NanozoxTM process	nanobubbles containing ozone with hydrogen peroxide coating	Ozone Technology Group. Kerfoot technology	380	mobile	8/day (operating); 0.025/bbl (175 gpd pipeflow)	–	–	–	–	50 kWh/d	–	–
MicroNOx	ClO2	NCH	–	–	–	–	–	–	–	–	–	–
PECO	photo-electriccatalytic oxidation	AquaMost	2200	mobile	–	"clean water/brine"	99% of bacteria killed	–	catalyst plates, UV light	0.0005 kWh/gal	7	Colorado, Texas, Utah, Canada

Table E.7: Integrated Treatment Technologies and Products

Technology Name	Technology Type	Vendor/Owner	Capacity, m3/d	Mobility	Costs $/bbl	Feed water quality, ppm	Treated water quality, ppm	Waste fraction,v/v%	Consumables	Power supply	Technology Readiness Level (TRL)	Current Region of Operations	References/Notes
POD	1) Collection and gravity settling of solids 2) Course filtration 3) Heated oil/water separation to recover immiscible hydrocarbons 4) Vapor compression and high velocity flash evaporation to recover brine and distilled water 5) Steam distillation integrated with the evaporator for recovery of methanol and other miscible hydrocarbons with UV and carbon filtration polishing	212 Resources	500-1500	semi-mobile	2.1-2.6 excl energy	300 TSS; 10-200000 TD	Customized	Dep on feed TDS; brine <450 000 TDS	Defoaming and KOH	50 kWh/m3	6	Wyoming, Colorado, Pennsylvania (Marcellus)	each pod: (2) evaporators, one (1) distillation column, and various pre and post treatment systems designed to process 3000 barrels per day of produced and flow-back water generated in the drilling and production of natural gas. http://www.212resources.com/water/flowback_use.html
CDM RO	RO	CDM Smith	3200	–	1.65-1.95	<40000 TDS	Customized	Dep on feed TDS; 10-50% brine	Higly dependent on the number and types of unit processes	–	5	California, Texas (desalination)	–
FracPure	chemical precipitaiton, filtration, evaporation, crystallization	Integrated Water Technologies	950	stationary	–	–	¡100 TDS	–	–	–	4	Marcellus	–
Aqualibrium	–	MI Swaco/Schlumberger	Customized	mobile	–	–	Customized	0.01	–	–	7	Marcellus, Canada	Don't think this technology is still offered but hard to tell as some material from 2011/2012 is still available online.
SIONIX MWTS - same as MAGNA MWTS	dissolved air flotation	Sionix Corporation	1500	stationary	–	–	Customized	–	Metal, salt, polymer	75 kW	–	–	–
ClearFlo Complete	forward osmosis, crystallizer	Oasys Water	–	–	–	–	–	<10%	–	–	3	China	http://oasyswater.com/solutions/clearflo-complete/
H2Oxidation	ozone, flocculation, filtration, clarifier, RO	H2Oxidation	687-2290	mobile	–	–	–	–	–	–	–	–	http://www.h2oxidation.com/3_10BB1.html
ShaleFlow	primary separator (gravity), dissolved air flotation, nutshell filtration, filter press	Veolia	–	mobile	–	–	<5 TSS, <5 Oil & Grease, <1 H2S, <1 Iron, <1 Manganese, Bacteria not detectable	–	–	–	–	–	http://www.veoliawatertech.com/vwst-northamerica/ressources/files/1/48371-ShaleFlowBrochureLR.pdf
PetroCleanse	electrocoagulation, reverse osmosis, clarification	Clean Runner	3200	–	–	–	Customized	–	–	–	–	Wyoming	–
FracCycle	vibration separation, nano-filtration	GreenHunter, now Fountain Quail Disposal	160	mobile and semi-mobile options	–	–	Customized	–	–	–	3	Marcellus, Utica	–
HIPPO platform/Octozone Technology	integrating robust technologies such as advanced oxidation, clarification, solids filtration, and membrane separation.	Orion Water Solutions	800	mobile	–	No pretreatment	Customized (though it's unclear it gets the salts out)	<5%	–	–	5	Eagle Ford, Permian Basin	http://www.omniwatersolutions.com/wp-content/uploads/2015/04/Permian-Basin-Produced-Water-Treatment.pdf, http://www.omniwatersolutions.com/oil-field-solutions/, http://www.sciencedirect.com/science/article/pii/S1359612813703380
Class I-IV	–	AquaPure (owns Fountain Quail)	320-1200	–	4-6	–	Customized	–	Coagulants, flocculants, acids, base, other - depending on treatment process	–	–	–	http://iogcc.ok.gov/Websites/iogcc/Images/2011\%20Midyear\%20Meeting\%20Presentations/11-06-29\%20IOGCC\%20Aqua-Pure\%20\%20Shale\%20Gas\%20Water\%20Management.pdf

Table E.8: Naturally Occurring Radioactive Material (NORM) Removal Technologies and Products

Technology Name	Technology Type	Vendor/Owner	Capacity, m3/d	Mobility	Costs $/bbl	Feed water quality, ppm	Treated water quality, ppm	Waste fraction,v/v%	Consumables	Power supply	Technology Readiness Level (TRL)	Current Region of Operations	References/Notes
Barium/Radium Removal Pretreatment System	Unclear but was added to existing municipal ion exchange softener regeneration system	Baxter & Woodman Consulting Eningeers	288	–	–	[Ra] 98-100 pCi/g; [Ba] 6-8 ppm	[Ra] 13 pCi/g; [Ba] <0.4 ppm	–	–	–	4	Illinois	Not much info on this technology. http://www.baxterwoodman.com/projects/bariumradium-removal-pretreatment-system/
–	Ion exchange	–	–	–	>$6/bbl produced water operational cost	–	–	–	–	–	7	–	–
DOWEX RSC resin	RSC resin	Dow Chemical Company	11000-22000 nanocuries/L	–	–	–	–	–	resin	–	7	–	Can't regenerate RSC resin
Sulfate precipitation	sulfate coprecipitation	ProChemTech International, Inc.	–	–	–	–	–	–	–	–	–	–	–
–	Sulfate treatment	–	–	–	1.41-2.35	–	–	–	–	–	–	–	–
–	Nanofiltration	–	–	–	concentrate transportation from central PA to OH and disposal by UIC: $11/bbl; transportation and disposal of concentrate: $7.70/bbl produced water	[Ba] = 6,200 (design case)	[Ba] = 1,152 (design case)	0.7	–	0.19 kWh/bbl	–	–	–
–	Lime soda precipitation	–	–	–	7.06-10.76	–	–	–	–	–	–	–	–
Modified lime soda precipitation	Modified lime soda precipitation	GE	–	–	$3.5-5.8/bbl produced water operational cost	–	–	–	–	–	3	–	–
–	MnO2 readsorption	GE	1400 mg/gm MnO2	–	$2.35/bbl produced water operational cost	–	[Ba] = 500	–	dilute HCl; MnO2	–	1	–	–
HMO with LayneOX	Hydrous Manganese Oxide	Layne	–	–	–	–	–	–	–	–	–	–	http://www.layne.com/en/divisions/water-resources.aspx
–	Filter sock disposal	Secure Energy Services	–	–	Dependent on amount of filter socks	–	–	–	–	–	7	US, Canada	Disposal service (pick up and dispose of socks)

Appendix F

Data for Decision Tree Variable Inputs

The following sections detail out the data used and the considerations made in determining the average/base value inputs into the decision tree.

F.1 Determining Average Municipal Water Price

To obtain the average water price of $0.11 per barrel assumed for the decision tree in Chapter 5, water transfer data from The Water Transfer Database was used [88]. The database can be downloaded for free from their website and contains data for over 2,220 water transfers in Colorado between 1987 and 2008. The entities involved in the water transfer are also noted in the database. For example, the database notes if the transfer occurred within a single entity (e.g. from one agricultural site to another) or between entities (e.g. from agriculture to urban). For the purposes of this study, only transfers to urban-use were included to calculate average municipal water prices. This specification was made in attempt to hone in on the likely prices a municipality might be willing to pay for water. In addition, data were only used for the years 2005-2009 to calculate the average water price. This resulted in 185 data points spanning water prices from 11.5 to 16,755 dollars per acre-foot. While this is a wide range, the majority of the water prices fall between 500 and 1150 dollars per acre-foot.

It is worth noting that a decade has passed since these data were collected. As such, current water prices could be different. Given growing pressures due to population increase and climate change, it is more likely that current water prices would be higher than those in the dataset. Due to the limited data and the fact that it is at least ten years old, the average water price (adjusted for inflation) was used to calculated the expected value.

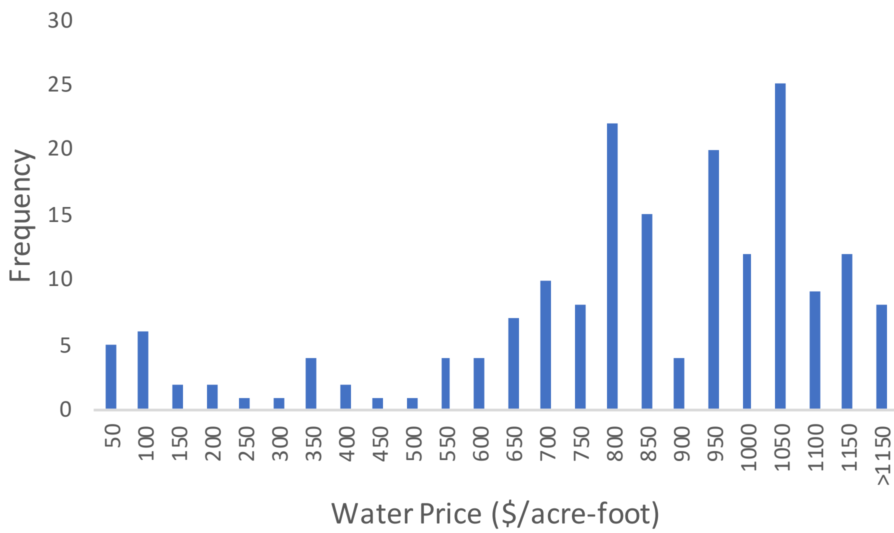

Figure F.1: The frequency of water prices paid by urban customers in Colorado between 2005 and 2009 (adjusted for inflation to 2017 equivalent) [88].

F.2 Determining Average Switchgrass Cost and Yield

Switchgrass cost and yield data from a single study were used for the purposes of the decision tree in Chapter 5 [8]. Figure F.2 shows the yield data from ten sites over five years of production. The first year is termed the establishment year and full production can take until the third growing season [8].

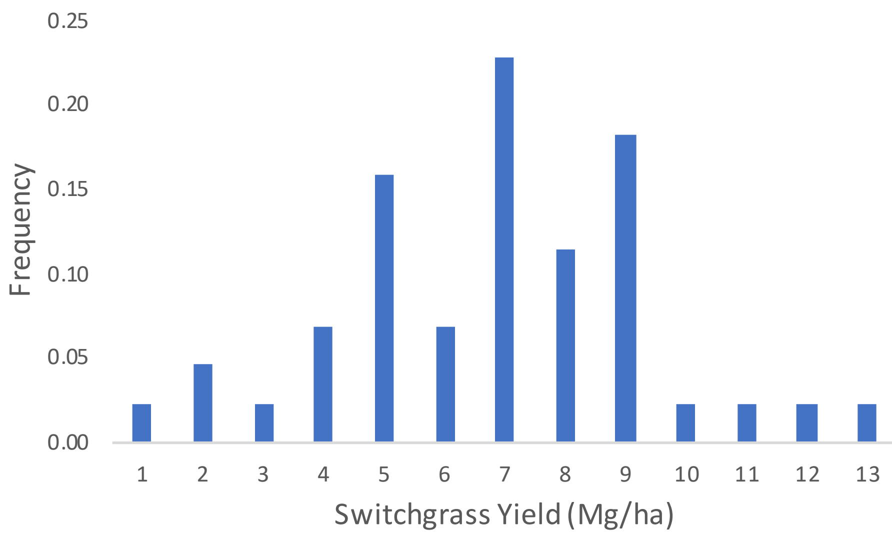

Figure F.2: This figure shows the frequency of switchgrass yield. [8]

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Vita

Yael Rebecca Glazer was born in Haifa, Israel and raised in the Bay Area, California. She received her Bachelor of Science degree in Bioengineering from the University of California at Berkeley in 2004 and spent the next seven years working at Genentech, a leading biotech company. The water crisis and climate change inspired her to return to graduate school to learn the skills to help address these dire concerns. She received her Master of Science in Environmental and Water Resources Engineering in 2014.

Permanent address: yael@utexas.edu

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